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Is "smart charging" policy for electric vehicles worthwhile? ☆

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ABSTRACT

Plug-in electric vehicles (PEVs) offer the potential for both reducing reliance on oil and reducing greenhouse gas emissions. However, they may also increase the demand for electricity during peak periods, thereby requiring the construction of new generating units and increasing total costs to electricity consumers. We evaluate the economic costs and benefits of policies that shift charging demand from daytime to off-peak nighttime hours, using data for two different independent system operators and considering a number of sensitivity analyses. We find that the total savings from demand-shifting run into the billions of dollars, though as a percentage of total electricity costs they are quite small. The value of smart charging policy varies significantly across electric grids. Time-of-use pricing is worthwhile under all of the cases we study, but the economic benefits of optimal charging of electric vehicles do not appear to justify investing in the smart grid infrastructure required to implement real-time pricing.

1. Introduction

Plug-In electric vehicles (PEVs) have the potential to transform the way the world powers a large portion of its transportation sector. As a result, PEVs are entering the market with a great deal of publicity and with high expectations; the vehicles likely will present many drivers with the opportunity to largely replace oil consumption with greater electricity consumption.

Since PEVs have yet to be deployed on a large scale, it remains unclear what impact they will have on the electric grid. A recent article in The Economist (2010) suggests that PEVs could pose challenges for electric utilities if their introduction leads to large spikes in demand at peak periods during the day. Indeed, according to the article, utilities "are concerned about highly concentrated pockets of ownership and the effects of everyone deciding to recharge their electric vehicles at once—as they inevitably will do when they return home from work. The local electricity system could be easily overwhelmed, and wider swathes of the grid brought to its knees in the process." Thus, quantifying the potential impact of PEVs on the grid and developing policies to avoid such detrimental impacts are essential to ensuring smooth commercialization and deployment of this new product.

State and local policies regarding deployment of smart grid infrastructure vary widely. Many states have taken no action to deploy smart meters. On the other hand, California and Hawaii are moving ahead with the funding and deployment of smart meters.[1] Xcel Energy's much-heralded "Smart Grid City" project in Boulder, Colorado, has had a portion of its costs disallowed by the Colorado Public Utility Commission on the grounds that the benefits of the meters have not been adequately established.[2]

The purpose of this research is to assess from an economic perspective whether policies to shift PEV charging from on-peak to off-peak hours are worthwhile. We consider two policies: one that would deploy programmable appliance timers to take advantage of a time-of-use (TOU) rate structure, and a second that would deploy sophisticated control equipment to take advantage of real-time pricing. To evaluate the economic impacts of these alternative policies, we developed a dispatch model for two independent system operators (ISOs): the Midwest Independent System Operator (MISO) and the PJM Interconnection (PJM). Both of these systems closely resemble the Standard Market Design (SMD) for wholesale markets proposed by FERC in 2002.[3] As is discussed in greater detail below, attributes of the SMD include day-ahead, hour-ahead, and real-time auctions, which utilize a bid-based, reliability-constrained, cost-minimizing algorithm to determine location-specific wholesale electricity prices based on marginal generation costs and transmission constraints.[4]

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[1] See California Public Utilities (2007) and Mead (2011) for details.
[2] Stevens and Lee (2011).
[3] Joskow (2006).
[4] See footnote 3.

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The remainder of the paper is organized as follows. Section 2 outlines the methodology used to calculate the economic impacts associated with different PEV charging scenarios, and the data used to build the dispatch model. Results and policy implications are discussed in Sections 3 and 4, respectively. Section 5 concludes.

2. Methodology

As mentioned earlier, both of the ISOs we study employ a bid-based, reliability-constrained cost-minimizing algorithm to dispatch generating units. We use a simplified model of the dispatch algorithm to characterize the impact of PEVs on the grid. Before discussing the specifics of our model, we present some background on bid-based electricity markets.

2.1. Background on bid-based electricity markets

To better understand the impact of various PEV charging patterns on the grid, it is important to be familiar with the mechanics of ISO-controlled electricity markets. ISOs dispatch power plants based on locational marginal prices (LMPs); buyers and sellers submit bids and offers for wholesale electricity for each hour of the day at various nodes throughout the transmission network. ISOs "stack" available generating units in order of increasing marginal cost, and dispatch them with the goals of minimizing costs and maximizing reliability. This creates LMPs at each node on the grid.

Nodes and LMPs are best understood by describing the relationship between generation and transmission; transmission lines are capacity constrained, meaning there is a limit to the amount of electricity that can be transported over any given transmission line. Transmission constraints mean that a given low-cost generator might not be able to provide power to a given demand pocket. Because of this constraint, high prices at a particular node of the ISO service territory may reflect transmission congestion as opposed to high marginal power plant costs. In the absence of congestion and line losses, and assuming zero transaction costs, prices across these nodes would be equal. As an example of the impact that transmission constraints can have on pricing, on July 19, 2005 at 5 pm, prices in Boston were approximately 2.5 times the price in Maine, despite the fact that these locations are physically near each other and are controlled by the same ISO; the price difference resulted from transmission congestion (Joskow, 2006).

Sellers in these markets receive the market-clearing price at a particular node, meaning that if the last generating unit needed to meet demand in any given hour at a particular node offered its electricity at $60 per MWh, all sellers at that node would receive that price. Total costs for electricity at that time would therefore be $60 multiplied by the total number of MWhs required to meet demand. An important aspect of these markets is that the lowest-cost power plants are deployed first, while higher-cost facilities are called upon as demand increases.

Supplier market power can be a concern in wholesale electricity markets, and there is evidence that transmission congestion creates situations in which suppliers may be able to successfully exercise market power leading to higher prices. That said, evidence suggests that such behavior is not prevalent in SMD markets in the Northeast (Joskow, 2006), and for the purposes of this exercise, we assume that power plant bidding behavior reflects actual marginal costs and does not take into account potential strategic factors such as exercising market power.

Figs. 1 and 2 outline the basic mechanics of supply and demand within an ISO service territory. Fig. 1 illustrates the typical shape of demand over the course of a day. The peak is the point in the day at which energy demand is highest, and it is typically in the middle of the day when most people are awake and business and manufacturing facilities are operating. The trough represents base demand and typically occurs around 3–4 am when most people are sleeping and when there is limited commercial or industrial activity. Fig. 2 illustrates how given levels of demand interact with a supply curve in which power plants are stacked and dispatched in merit order based on price. The leftward shift in the demand curve shown in the figure illustrates a move from peak to off-peak periods, and demonstrates how a reduction in demand can lead to a lower market-clearing price (and lower total costs of electricity), given the shape of a typical electricity supply curve.

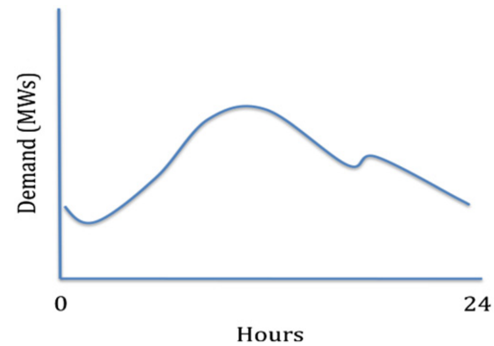

Fig. 1. Daily demand.

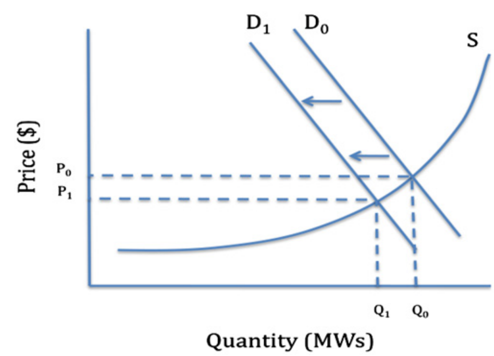

Fig. 2. Supply and demand.

There are other aspects of ISO-controlled markets that are not addressed in this paper. For example, in MISO, there is a day-ahead energy market, a real-time energy market, and a financial transmission rights market (FTRs). Buyers and sellers meet on these markets, and MISO oversees the auction process while ensuring that energy supply is secure and reliable. Hourly load and pricing is scheduled in the day-ahead market, while the real-time market serves to smooth any imbalances, with locational marginal prices clearing every 5 min (versus hourly in the day-ahead market). FTRs serve as a hedge against high congestion costs by providing the FTR holder with revenue associated with the cost of congestion at a particular location (Joskow and Tirole, 2000).

Because our model is designed to capture macro-level impacts of PEVs on the grid (as opposed to calculating prices at various nodes on the grid), we match overall supply with overall demand to arrive at hourly market-clearing prices for the ISOs as a whole, meaning we do not model LMPs, transmission congestion, or a distinction between the day-ahead and real-time markets. Given the uncertainties associated with forecasting, we believe our approach is appropriate.

2.2. Description of the model

Our dispatch model uses supply and demand forecasts to calculate the projected wholesale price of electricity for each hour of each day from 2010 to 2030. Firstly, we calculated a marginal cost curve for each ISO using data for all power plants within the ISO territory. To arrive at the marginal cost curve, we took the following steps (see Section 2.3 for data sources used for steps 1–4):

1. We began with nameplate capacity for each power plant in the ISO.
2. Multiplied by
   a. the equivalent availability factors (EAFs) for coal, nuclear, natural gas, municipal solid waste, biomass, landfill gas, and oil plants,[5] or
   b. the average of the 2004 and 2005 (the most recent years available) capacity factors for wind and hydro facilities from eGRID.
3. Multiplied by the appropriate forecast fuel price (converted into $/MWh), and
4. Added SO_2 costs ($/MWh) based on emissions levels for each plant.

For business-as-usual demand (i.e. without PEVs), we began with actual hourly demand levels from 2009 and applied growth rates for both ISOs (data sources for the demand analysis can be found in Section 2.3). We then solved for market-clearing prices for each hour of our study period, and computed total expenditures on electricity. This provided the reference case against which we evaluate the impacts of PEVs on the grid.

Both load and capacity on each ISO are projected to expand over this time period, and the model assumes that capacity expands in line with various ISO forecasts. For MISO, we used the Reference case from a transmission planning document, which MISO considers a "status quo" scenario that takes into account, for example, existing legislation and Renewable Portfolio Standard (RPS) requirements.[6] This forecast is specific to the year 2024, so we expanded capacity of the various generation asset-types linearly to meet the 2024 forecast, and then continued to expand at the same linear rate through 2030.

Unlike MISO, PJM does not forecast generation expansion. However, the ISO does publish projects that are active in its generation queue (see Appendix B). We expanded capacity in PJM so that total capacity additions in each year equal PJM's projected peak load growth ("PJM RTO with ATSI" growth forecast found in the PJM Load Forecast Report, Table B-1) plus a reserve margin of 16%. The 16% reserve requirement is an estimate based on the requirement projected in the PJM Reserve Requirement Study (2009) (specifically in Fig. II-3 within that document). We expanded capacity of different generation assets according to their respective proportions in the generation queue (based on the numbers in Appendix B), and we assumed a wind capacity credit of 20%, meaning only 20% of wind nameplate capacity "counts" toward the capacity expansion required due to peak load growth.

We built on this core model to analyze the economic impact of adding PEVs to business-as-usual demand. To do so, we adjusted elements of both forecasted supply and forecasted demand as outlined in the scenario descriptions in Section 2.4. We then solved the model again for the new set of equilibrium prices and total electricity expenditures. By comparing these results against those of the business-as-usual case, we can identify the economic impacts of charging policy in each of the ISOs we study. We distinguish two types of economic impacts. First, the increased load results in a higher market-clearing price for electricity since the ISO will have to dispatch more plants, likely with higher generating costs, to meet this demand.

Secondly, utilities will be forced to build or purchase additional capacity to meet any increase in peak demand associated with PEVs. The cost of this capacity is assumed to be $80/kW-year, a proxy used by the Lawrence Berkeley National Laboratory to represent the carrying cost of a simple-cycle, natural gas peaking plant (Cappers et al., 2009).

The overall costs of these scenarios, and the cost differences between the scenarios, provide an estimate of the economic value of shifting charging times from peak periods to off-peak periods. Costs are totaled for each year from 2010 to 2030 and are discounted at 5%, which is the approximate cost of capital for an electric utility in the Central United States (Damodaran, 2010), to arrive at a Net Present Value of the incremental costs associated with each charging scenario.

2.3. Data sources

We collected data for all power plants within MISO and PJM from the EPA's Emissions & Generation Resource Integrated Database (eGRID) (United States Environmental Protection Agency, 2009). These data include power plant name and location, nameplate capacity, capacity factor, fuel type, heat rate, and emissions levels. Power plant equivalent availability factors (EAFs) were taken from the North American Electric Reliability Corporation (NERC).[7] The EAF for a given type of power plant (e.g., pulverized coal or natural gas combined cycle) adjusts that type of plant's available hours by taking into account statistically predictable things such as seasonal de-rated hours (hours when the plant is offline) and planned de-rated hours.

Power plant fuel sources include nuclear, coal, natural gas, oil, hydro, landfill gas, wind, solar, and biomass. To calculate the marginal cost, or supply, curve within each ISO, we used the Energy Information Administration (EIA) Annual Energy Outlook 2010 Reference Case fuel price forecasts for coal (AEO 2010 Table 15), natural gas (AEO 2010 Table 13), and oil (AEO 2010 Table 12) (United States Department of Energy, 2010). Data for other fuel sources were not needed because power plants with such fuel sources typically bid into the grid at $0 due to either zero fuel cost (as in the case of wind) or the high expense of operating below capacity (as in the case of nuclear).

The price of SO_2 allowances is assumed to remain constant at $200 per ton based on an analysis done by the US Energy Information Administration (United States Department of Energy, 2001).

A sample calculation illustrating how we used this data to arrive at a supply curve can be found in Appendix A.

On the demand side, for baseline information (i.e. business-as-usual with no PEVs) we used published hourly load data for 2009 from MISO[8] and PJM[9] and applied load growth forecasts. We used the ISOs' own peak growth forecasts as a proxy for overall load growth to approximate business-as-usual energy demand from 2010 to 2030; specifically, for MISO we used the "50/50 Forecast" found in MTEP (2009), Fig. 5.2-3, and for PJM we used the "PJM RTO with ATSI" growth forecast found in the PJM Load Forecast Report, Table B-1.[10,11] The MISO and PJM forecasts end in 2018 and 2025, respectively, so an average growth rate is applied in each year thereafter through 2030.

[5] NERC does not publish EAFs for municipal solid waste (MSW), biomass, and landfill gas (LFG) facilities, so we used the EAF for natural gas as a proxy due to the fact that MSW, biomass, and LFG facilities are functionally similar to natural gas facilities.

[6] MTEP (2009): Midwest ISO Transmission Expansion Plan (2009).

[7] North American Electric Reliability Corporation (2009).

[8] LCG Consulting (2010).

[9] PJM—Hourly Load Data (2010).

[10] MTEP (2009): Midwest ISO Transmission Expansion Plan (2009).

[11] PJM Load Forecast Report (2009).

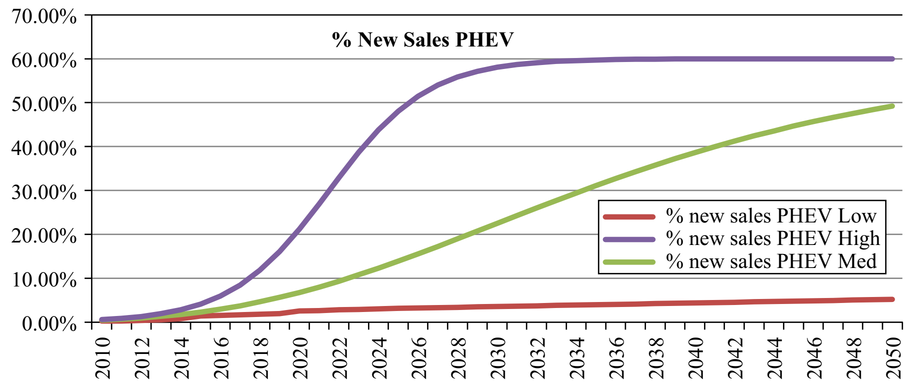

Fig. 3. Midsize PEV sales as a percentage of total PEV sales.

2.4. Scenarios included in the analysis

We used a scenario-based approach to account for uncertainty surrounding forecasting the impact of PEVs. Specifically, we adjusted the following inputs: level of PEV penetration, PEV charging scenarios, and carbon price. As is typical with scenario analysis, we consider each scenario independently, which results in a sensitivity analysis that provides insight into the robustness of our findings. The explicit modeling of uncertainty is beyond the scope of this paper, but would be a worthwhile topic of future research.

2.4.1. PEV penetration

We added PEV load to business-as-usual, non-PEV load (described in Section 2.2) based on low, medium, and high PEV penetration scenarios, which were developed in a report for the Michigan Public Service Commission (MPSC) by the Center for Sustainable Systems (CSS) at the University of Michigan's School of Natural Resources and Environment (Camere et al., 2009). To develop these scenarios, the CSS team:

1. Estimated new vehicle sales in each car class within Michigan by calculating the year-over-year change from May 2008 to 2009 in the number of vehicle registrations for cars with model years 2008, 2009, or 2010; this data was obtained from the Michigan Secretary of State's office.
2. Forecasted future sales in Michigan by car class based on the sales growth rate forecasts from the EIA Annual Energy Outlook 2009 (United States Department of Energy, 2009) Stimulus-Included Reference Case projections, found in Table 50, for total light-duty vehicles sales (LDV) for the East North Central Region.
3. Applied low, medium, and high PEV penetration rates (as a percentage of new LDV sales) to estimate the number of PEVs sold in a given year.

See Appendix C for additional detail on the CSS report's PEV penetration methodology.

Fig. 3 details PEV sales in the midsize class as a percent of total new midsize vehicle sales under the low, medium, and high scenarios. As an example, in the CSS report, the percentage in a given year is multiplied by total vehicle sales for that class within Michigan in that year, and this process is repeated for each vehicle class size.

The CSS report focused on PEV penetration within Michigan, so we used a population multiplier to account for the larger populations (as compared to Michigan) within MISO and PJM. As an example, the population within the MISO service territory is approximately 4 times the population within the state of Michigan, so we assumed that the number of PEVs within MISO would be approximately 4 times the number of PEVs within Michigan.

Table 1
Summary of PEV battery specifications used in model.

Battery capacity (kWh)	Floor state of charge cutout	Floor (equivalent kWh)	Ceiling state of charge cutout	Ceiling (equivalent kWh)	Usable capacity of battery (ceiling minus floor) (kWh)
16.0	30%	4.8	80%	12.8	8.0

2.4.2. PEV charging scenarios

In our model, we vary not only PEV penetration levels, but also PEV charging patterns. Certain elements of charging patterns are held constant throughout all scenarios For instance, for all scenarios, we used a battery capacity of 16 kWh for each vehicle, which is based on preliminary specifications for the 2011 Chevy Volt and, in our estimation, is a likely average for PEVs in general.[12] The expected range of charge of the battery is a floor of 30% state of charge and a ceiling of 80% state of charge, meaning we used a 50% usable capacity for the battery, or 8 kWh, which is consistent with the Volt's expected range of charge.[13] Note that, similar to our approach for modeling PEV penetration scenarios, we incorporated data from the CSS team into our PEV charging scenarios. The CSS report actually assumes a 10.4 kWh usable capacity, but the CSS team recalculated all of the load expectations to provide us with data for our 8 kWh expected usable range. See Table 1 for an overview of the PEV battery specifications used in our model.

For all scenarios, and consistent with the assumptions by Camere et al. (2009), we used a battery charging efficiency of 88% (i.e. 12% loss). The charging efficiency does not affect the instantaneous power generation requirement (discussed in the next subsection), but it does increase the total power generation required to complete the charge of the vehicle.

There are two aspects of PEV charging that vary in our model, specifically (1) 120 versus 240 V charging voltages and (2) the timing of PEV charging. These variables are discussed in the next two sub-sections.

2.4.2.1. 120 vs. 240 V charging. The actual power draw of an individual PEV is a function of a number of variables. Two key determinants are the voltage and the amperage of the charger and outlet connection infrastructure. As mentioned above, to determine our scenarios, we looked at the Chevy Volt as a model; the Volt will be charged by either a portable 120 V charging unit that can plug into any standard outlet or a dedicated 240 V unit that, similar to a dryer, will require installation into a more powerful connection. The

[12] Chevy Volt Specs: Preliminary Specification: 2011 Chevrolet Volt (2011).
[13] How Charging of the Battery Works in the Chevy Volt (2008).

Table 2
Power requirements per vehicle by charging method.

	Voltage	Amperage	Transmission losses (%)	Total instantaneous power generation required (kW)
Scenario 1	120	12	9	1.57
Scenario 2	240	16	9	4.19

tradeoffs between different voltages and amperage levels for charging can be summarized as follows: the standard 120 V equipment will recharge the battery in 6 h at 12 amps, whereas the 240 V equipment running at 16 amps will recharge the battery in 3 h.[14] We analyzed the 120 V – 12 A and 240 V – 16 A scenarios (note that there is also a 120 V – 8 A charge option that we did not analyze because we do not expect this to be a prevalent charging scenario).

In addition, we factored in an assumed transmission and distribution loss to determine total instantaneous generation required to provide the delivered electricity at the outlet. We assumed 9% transmission and distribution loss, a figure also borrowed from the CSS draft report.[15] Accordingly, the instantaneous power requirements for an individual vehicle for the two scenarios we analyzed are summarized in Table 2.

It is important to note a key difference between the 240 V and 120 V scenarios. The total power required to charge the vehicle is not materially different, but the instantaneous power draw, and therefore the minute-by-minute or hour-by-hour load, is quite different. The 240 V scenario, instantaneously, requires approximately 2.66 times more power.

2.4.2.2. Timing of PEV charging. We also vary the timing of PEV charging to analyze the cost differences between three specific charging patterns. First, we analyzed a scenario in which charging is permitted throughout the day, meaning customers can charge at will. For the scenario in which PEV charging occurs at any point throughout the day, PEV charging patterns were borrowed from the same CSS draft report discussed above. These charging patterns are based on a 2005 National Household Travel Survey (NHTS) that evaluated driving behavior, and data recorded in this study included trip length, trip start and end times, and day of the week.[16]

These data were then used to simulate electricity and gasoline consumption had the drivers been driving PEVs. Since these vehicles have not yet been commercially deployed, there is limited public information available, so the CSS report determined electricity depletion rates for different vehicle classes by averaging data available in press releases and in academic sources. The amount of electricity expended over the course of a day is calculated based on vehicle class and the NHTS trip length data. The amount of electricity expended is subsequently required from the grid, and it is assumed that charging commences at the exact time that the trip ends.[17]

We also consider two alternative charging scenarios. In the first, all PEVs are charged during the 12–8 am timeframe. In this scenario, we took the total 24 h PEV load demand, divided by 8 (the number of hours between 12 and 8 am), and allocated the load equally to each hour from 12 to 8 am. In the second scenario, PEV charging is optimized in a window stretching from 9 pm to 9 am using an optimization algorithm to minimize costs.

[14] Charging the Chevy Volt (2009).
[15] Camere et al. (2009).
[16] See footnote 15.
[17] See footnote 15.

Fig. 4 illustrates the effects of charge-shifting. The large medium-gray area in the charts represents total non-PEV energy demand in a given day, using MISO as an example (market clearing prices for each hour throughout the day are calculated as described in the Bid-Based Electricity Markets section above). The small darker region represents PEV load; the chart on the left is an example of PEV load with owners charging at the time of their choice throughout the day, whereas the chart on the right represents a scenario in which charging is restricted to the midnight to 8 am period. Total energy costs are calculated by multiplying demand at each hour by the market-clearing price at each hour.

2.4.3. Carbon price

It is possible that there will be a price associated with carbon emissions in the US at some time in the future, and we therefore included a carbon price as an option in our model. One reasonable estimate for a carbon price was derived from legislation that was passed in the House of Representatives of the US 111th Congress. H.R. 2454—the American Clean Energy and Security Act of 2009. Among other things, H.R. 2454 would establish an economy-wide cap & trade system for greenhouse gas emissions. The EPA performed an economic analysis of this legislation, including forecasting of CO_2 prices; in our model, we use Scenario 8, the “Core Policy Scenario,” as our CO_2 price through 2030; the price trajectory is shown in Fig. 5.[18] Note that ADAGE and IGEM are two alternative forecasting models; we used the average of the two prices. Further discussion of these models can be found at the EPA’s Climate Economic Modeling webpage: http://www.epa.gov/climatechange/economics/modeling.html.

2.5. Scenarios modeled

As described above, we identify a number of variables of interest for creating alternative scenarios: MISO versus PJM, level of PEV penetration, 120 V versus 240 V charging, and whether there is a carbon price or not. (We also consider an “environmental scenario” within MISO; PJM does not identify such a scenario.) Taking all possible combinations of these variables would create 24 possible scenarios, each of which is to be analyzed for three different possible charging patterns. To make the analysis more manageable, we focused on the impacts of varying PEV penetration, introducing a carbon price, and changing the voltage at which charging is done. This led to the following smaller range of scenarios:

1. MISO base case: medium PEV penetration, 120 V—12 A, no carbon price.
2. PJM base case: medium PEV penetration, 120 V—12 A, no carbon price.
3. MISO, medium PEV penetration, 120 V—12 A, carbon price.
4. PJM, medium PEV penetration, 120 V—12 A, carbon price.
5. MISO, medium PEV penetration, 240 V—16 A, no carbon price.
6. PJM, medium PEV penetration, 240 V—16 A, no carbon price.
7. MISO, medium PEV penetration, 120 V—12 A, environmental growth.
8. MISO “maximum impact”: environmental growth, high PEV penetration, 240 V—16 A, carbon price.
9. PJM “maximum impact”: high PEV Penetration, 240 V—16 A, carbon price.

For each of these scenarios, we calculated the economic impacts of the alternative PEV charging patterns discussed in Section 2.4.2.2.

[18] US Environmental Protection Agency (2010).

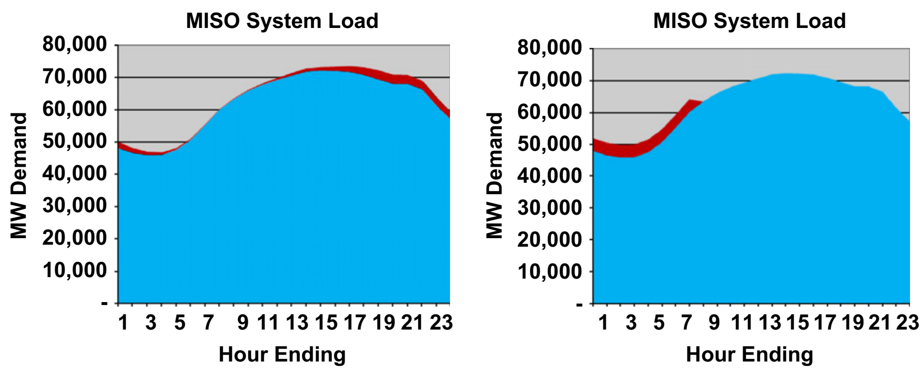

Fig. 4. Shifting PEV load from peak to off-peak.

	2012	2015	2030	2050
ADAGE	$14	$16	$33	$87
IGEM	$13	$15	$32	$85

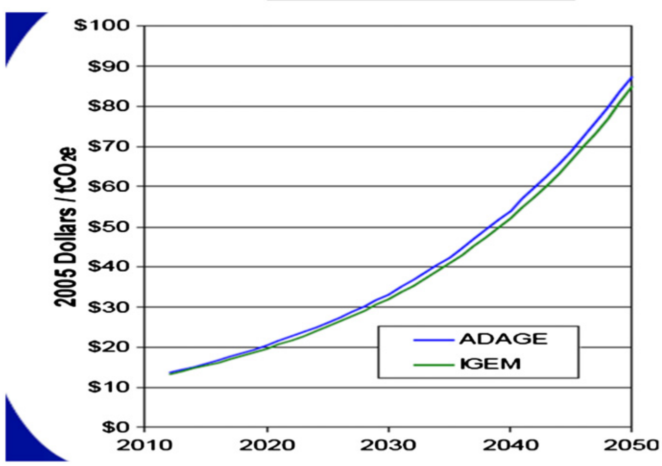

Fig. 5. GHG allowance prices. (See footnote 20.)

3. Results

In this section, we report results for the two ISOs we studied, starting with MISO and then continuing with results for PJM. As outlined in the previous section, we consider four scenarios for each ISO. In each case, we study the effects of charge shifting, and how they break down into energy and capacity cost savings.

3.1. MISO results

MISO's generation capacity is approximately 139,000 MW (for purposes of meeting market demand) and 159,000 MW (for reliability purposes); 51.3% of this generation capacity is coal.[19] In 2009, the average hourly demand within MISO was 60,900 MW and the peak system demand was 96,326 MW. The combination of relatively low demand (meaning there is significant excess capacity) and significant coal generation capacity within MISO results in a marginal clearing generation unit that is almost always coal. The clearing plant transition from coal to natural gas typically occurs at roughly 120,000 MW. Accordingly, in 2009, MISO system demand almost never touched the relatively steep portion of the supply curve, which is largely composed of natural gas units. Furthermore, even with the additional electricity demand associated with bringing PEVs online and charging them during peak times, there is generally sufficient unused coal capacity to meet this additional demand and to still avoid reaching the steep part of the supply curve. Based on this, we would expect the wholesale energy cost savings of shifting PEV charging to off-peak times (shifting from one coal plant to a somewhat more efficient coal plant) to be smaller within MISO than within ISOs in which demand levels reach the steep part of the supply curve more often (meaning demand might shift from a natural gas plant to a coal plant).

3.1.1. Economic impact of changing PEV charging patterns in MISO

For each scenario, we analyzed the impact of charging at various points throughout the day. Specifically, we explored difference in costs (1) assuming customers charge at will (2) assuming that charging is forced equally across the hours of 12–8 am, and (3) assuming that charging is optimized to minimize costs from 9 pm to 9 am Table 3 provides an overview of the savings associated with shifting the charging times, and these results are discussed below.

All of the savings listed in Table 3 represent a reduction in costs derived from controlling PEV charging times, as opposed to allowing customers to charge at will. Energy savings result from shifting PEV charging from peak periods in which energy is relatively more expensive to off-peak periods when energy is relatively less expensive. In addition, by shifting PEV demand from peak hours to off-peak hours, there is a savings associated with avoided capacity costs that result from a decrease in the absolute peak demand level. The breakdown of the relative proportion of avoided energy and avoided capacity costs can be found in Fig. 6.

Across all scenarios, avoided capacity savings make up the majority of total savings from shifting PEV charging to off-peak times. It is worth noting that although wholesale electricity costs required to charge PEVs comprise the majority of the costs of adding PEVs to the grid, avoided capacity savings comprise the majority of the savings associated with shifting PEV charging to off-peak times. At first glance, this may sound counterintuitive. However, this difference is subtle and illustrates the unique characteristics of MISO. Because MISO has significant overcapacity, of which approximately 51% is coal, the off-peak and peak wholesale prices of electricity are not significantly different. The direct electricity costs of charging PEVs are significant, but not because the peak price of electricity is significantly higher than the off-peak price. Rather, costs of charging PEVs are significant because of the sheer volume of electricity required to charge the vehicles. Accordingly, shifting the charging of PEVs into the off-peak hours of 12–8 am does not significantly reduce wholesale electricity costs, but it does reduce absolute peak demand levels, which leads to significant avoided capacity savings. This finding could be very different in an ISO in which the marginal clearing

[19] Midwest ISO Corporate Information (2010).

Table 3
Savings from shifting charging times in MISO.

Scenario	NPV of energy costs savings—12–8 am All $ values in millions	NPV of avoided capacity savings—12–8 am	NPV of savings by shifting charging—12–8 am[a]	NPV of energy costs savings—optimal shift	NPV of avoided capacity savings—optimal shift	NPV of savings by shifting charging—optimal shift[a]
	[1]	[2]	[1]+[2]	[3]	[4]	[3]+[4]
Base case	$52	$172	$224 (0.11%)	$63	$172	$234 (0.11%)
Base case w_enviro	$79	$172	$250 (0.12%)	$91	$172	$263 (0.12%)
Base case w_carbon price	$52	$172	$223 (0.11%)	$66	$172	$237 (0.11%)
Base case w_240 V	$73	$264	$338 (0.16%)	$84	$264	$349 (0.16%)
Maximum impact[b]	$349	$1060	$1409 (0.67%)	$387	$1060	$1448 (0.68%)

[a] Savings as % of total base case system cost in parentheses.
[b] Maximum impact includes high PHEV penetration rate, 240 V—16 A charge scenario, carbon price, and enviro generation capacity growth scenario.

plant is a natural gas plant positioned at a steeper point along the supply curve, in which case shifting PEV charging from peak to off-peak times might result in shifting charging from a costly natural gas plant to a less-expensive coal plant.

An additional result worth noting is that we found very little difference in savings between an optimal charge and a charge in the 12–8 am timeframe. The optimal charge yields an increase in savings over the 12–8 am charge of 2.7–6.3%, depending on the scenario. Any costs associated with getting consumers to charge PEVs during the "optimal" charge times instead of the 12–8 am charge time would have to be weighed against these savings, as we discuss in the policy analysis of Section 4.

3.2. PJM results

In 2009, PJM's generation capacity was approximately 127,000 MW (market) and 167,000 MW (reliability); 50.5% of this generation capacity is coal and 36% is natural gas.[20] In 2009, the average hourly demand within PJM was 77,869 MW and the peak system demand was 126,805 MW. In 2009, the marginal clearing plant for PJM during shoulder and peak hours was often natural gas, which is more costly than coal; the natural gas plants are typically positioned along the steep part of the supply curve. We therefore would expect PEV penetration, particularly if PEVs are charged during peak times, to have a more significant impact on the wholesale cost of electricity than it does in MISO, where the typical peak and shoulder period plants are coal.

3.2.1. Economic impact of changing PEV charging patterns within PJM

The potential savings associated with restricting PEV charging times to specific hours of the day within PJM are illustrated in Table 4.

Within PJM, we found that the savings from shifting PEV charging from peak to off-peak hours is significant from an absolute dollars perspective (albeit small as a percent of total system costs), ranging from $1.1 billion to $5.09 billion. The biggest difference between PJM and MISO is that in PJM, the majority of the savings from shifting comes from reduced wholesale electricity costs (see Fig. 7), whereas in MISO most savings come from avoided generation capacity savings (see Fig. 6). This also can be explained by the typical marginal plant within each ISO. In PJM, many peak hours are served by a natural gas marginal plant. Therefore adding PEVs during peak hours is particularly costly. However, shifting charging to off-peak hours may shift the marginal plant to a coal fired plant, resulting in a significantly lower wholesale price of electricity (note that this result changes somewhat with a carbon price because the off-peak coal plant becomes relatively more expensive).

4. Policy implications

The economic analysis in the foregoing section provides a number of new insights into the economic value of smart charging for PEVs on different electric systems. As mentioned in the Introduction, state policy within the US towards the deployment of smart meters varies widely, with some states supportive and others opposed. Our analysis in the preceding section sheds light on this variation: the economics of smart charging varies substantially from one electric grid to another. In particular, the value of smart charging depends heavily upon the balance of supply and demand, and upon the nature of the fuel used for generation at the margin during peak and off-peak periods.

Whether public policy should encourage smart charging depends upon both the benefits of charge-shifting on a particular grid, and the costs of the infrastructure required. Our analysis in Section 3 considered two possible approaches to smart charging, one that can be implemented via simple time-of-use pricing(TOUP) and one that would require real-time pricing (RTP). We also considered charging at both 120 V and at 240 V. Residential homeowners with electric outlets in their garages could take advantage of 120 V charging on a TOU rate with the purchase of a simple appliance timer, the cost of which ranges from about $12 to about $60 at www.amazon.com. In order to optimize smart charging, by responding to real-time pricing, a smart meter must be installed, at a cost of approximately $150 (Alcott, 2010). Customers who want to use 240 V charging will have to install new equipment, at costs estimated to run between $1500 and $2500.

In order to assess whether the costs of new infrastructure are warranted, it is necessary to evaluate the savings associated with smart charging on a per-vehicle basis. To do so, we divide the NPV of savings derived in previous sections by the number of PEVs on the road in 2030. This provides a conservative estimate of the savings per vehicle, since some PEVs purchased early in the period of study would have been replaced by the year 2030. The results for the base case and the two alternative scenarios with greatest impact are presented in Table 5, which presents results

[20] PJM Electric Market: Overview and Focal Points (2010).

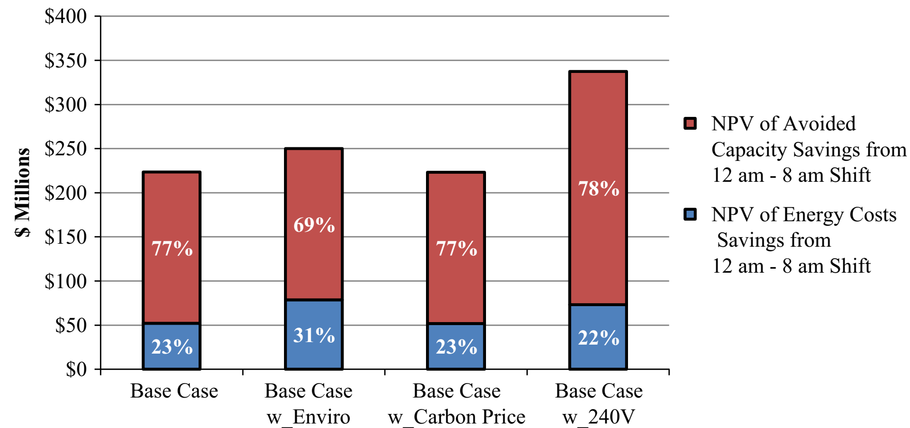

Fig. 6. Savings from shifting PEV charging in MISO.

Table 4
Savings from shifting charging times in PJM.

Scenario	NPV of energy costs savings—12–8 am All $ values in millions	NPV of change in total system wholesale cost of electricity for non-PEV load by adding PEV load	NPV of Savings by shifting charging—12–8 am[a]	NPV of energy costs savings—optimal shift	NPV of avoided capacity savings—optimal shift	NPV of savings by shifting charging—optimal shift[a]
	[1]	[2]	[1]+[2]	[3]	[4]	[3]+[4]
Base case	$1132	$306	$1438 (0.42%)	$1422	$306	$1729 (0.50%)
Base case w_carbon price	$632	$306	$938 (0.27%)	$831	$306	$1138 (0.33%)
Base case w_240 V	$1498	$433	$1930 (0.56%)	$1801	$433	$2234 (0.65%)
Maximum impact[b]	$3003	$1515	$4518 (1.31%)	$3576	$1515	$5091 (1.48%)

[a] Savings as % of total base case system cost in parentheses.
[b] Maximum impact includes high PHEV penetration rate, 240 V—16 A charge scenario, carbon price, and base case capacity growth scenario.

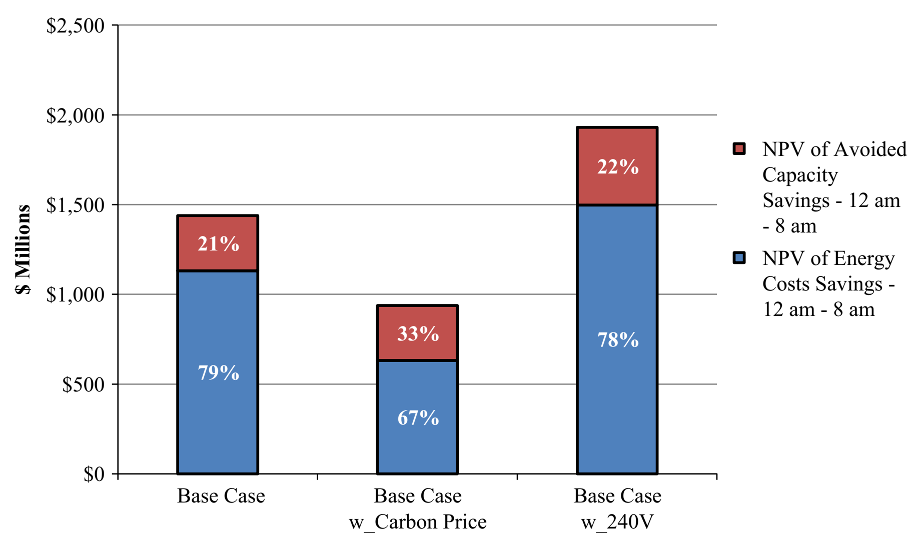

Fig. 7. Savings from shifting PEV charging in PJM.

for time-of-use pricing, real-time pricing, and the incremental savings of going from TOUP to RTP.

The table shows that the savings from smart charging using simple TOU pricing are large enough under all scenarios to justify the installation of an automated appliance timer. The value of the savings per vehicle is much greater in PJM. However, even in PJM the incremental savings from switching to real-time pricing are not great enough to justify the installation of smart meters. In addition, the savings from smart charging at 240 V are never enough to justify installation of the necessary infrastructure. (Consumers might, of course, desire the 240 V charger for its convenience value.)

From a policy perspective, our results imply that states ought to be positively disposed towards policies that would encourage PEV owners to take advantage of TOU pricing, since the savings to

Table 5
Net present value of energy savings per vehicle.

	MISO			PJM		
	TOUP	RTP	Δ(RTP-TOUP)	TOUP	RTP	Δ(RTP-TOUP)
Base case	$55.64	$58.12	$2.48	$285.71	$343.53	$57.82
Base case w/240 V	$83.95	$87.43	$3.48	$383.47	$443.87	$60.40
Maximum impact	$109.26	$112.28	$3.02	$280.27	$315.82	$35.55

the electric system more than outweigh the slight additional costs of simple appliance timers. However, smart charging of PEVs alone is not enough to justify state subsidies for the deployment of smart meters or 240 V charging infrastructure.

5. Conclusions

In this paper, we have presented an analysis of alternative policies to shift charging patterns for PEVs away from periods of peak demand. We studied in detail the characteristics of two large independent system operators (ISOs), the Midwest Independent System Operator (MISO) and the Pennsylvania–New Jersey–Maryland Interconnection (PJM). We evaluated both time-of-use pricing and real-time pricing, incorporating the costs of new infrastructure that would be required to implement either pricing policy.

MISO and PJM have very similar supply curves with 159,000 MW (reliability) and 51.3% coal and 167,000 MW (reliability) and 50.5% coal, respectively. The key difference between the ISOs is the average level of demand, which in 2009 was 77,869 MW for PJM and 60,987 MW for MISO. The central impact of this difference is that costly natural gas is the typical daily peak-clearing plant for PJM, whereas less-expensive coal is the typical peak clearing plant for MISO. Furthermore, MISO has significant excess coal capacity. Thus, adding PEVs during peak hours in PJM is far more costly than it is in MISO. Accordingly, shifting charge times to off-peak hours within PJM results in the PEV load being charged with a coal plant instead of a natural gas plant. In MISO, the shift would be from coal to coal. Therefore, the energy cost savings associated with shifting charge times is greater within PJM than MISO.

There are significant absolute dollar savings associated with shifting PEV charge times, although they represent a fairly low percentage of total system costs. A simple PEV 12–8 am time-of-use tariff coupled with a circuit timer between the PEV outlet and the PEV plug appears to be the most economical way to maximize the net benefits of shifting charging times. Shifting PEV charging optimally to minimize energy costs results in modest additional savings compared to shifting PEV charging equally across each hour in the 12–8 am window, and is unlikely to justify the incremental infrastructure costs that would be required to implement it.

In future work it would be interesting to utilize a stochastic rather than a deterministic approach to estimating the benefits of charge shifting. This would allow for estimating a range of potential benefits, with confidence intervals attached. Nevertheless, we expect that our fundamental results regarding the relative cost-effectiveness of time-of-use pricing relative to real-time pricing will be robust to such analysis.

Appendix A

This appendix is designed to illustrate how power plant data was used to construct the marginal cost curve for an ISO. Specifically, this appendix discusses the data for the Warner Lambert plant in Michigan and how the data is used to calculate the MISO supply curve:

Plant name: Warner Lambert.
Location: Michigan.
Fuel type: Natural Gas.
Nameplate capacity: 12.4 MW.
Capacity factor: 24%.
SOx output: 0.0306 lb/MWh.
Heat rate: 8500 BTU/kWh.
Fuel price: $6.42/MBTU.
Equivalent availability: 91%.
Net capacity: 11.33 MW.

To calculate how this plant fits into the overall MISO marginal cost curve, we first multiplied the plant capacity by the plant equivalent availability factor to determine the "Net capacity," which is 11.32 MW. Essentially, this means that, on average, the Warner Lambert plant provides 11.32 MW of capacity to MISO (note that for hydro and wind, we use an average capacity factor from 2004 to 2005 eGRID data, the most recent years available, instead of an equivalent availability factor. Capacity factor more accurately represents wind and hydro availability than does equivalent availability factor due to the intermittent, weather-determinant nature of these resources).

To calculate at what price this plant will bid into MISO, we need to calculate marginal cost for the plant. This is calculated first by taking the plant's heat rate (8.5 MBTU/MWh) and multiplying by the price of natural gas (using annual data from the EIA Reference forecast). Next, we add the cost of SOx by multiplying the SOx price ($/lb) times the emissions rate (lb/MWh) for the plant. For Warner Lambert, the fuel cost is $6.42/MBTU $\times$ 8.5 MBTU/MWh, or $54.57/MWh. The SOx cost is 0.0306 lb/MWh $\times$ $0.10/lb, which, when added to the fuel costs, brings the total marginal cost for Warner Lambert to $54.57 (SOx costs adds just $0.003 to the total).

Of course, this plant is only called upon when demand requires its use. In terms of the overall MISO marginal cost curve, this plant would be called upon when demand reaches approximately 95,000 MW. Below that level of demand, there are less expensive plants (in terms of marginal cost) that would be called into use. Most of these plants are coal, nuclear, wind, and landfill gas facilities that have very low marginal costs.

The overall MISO marginal cost curve is computed by doing similar calculations for all power plants within the MISO service territory.

Appendix B

See Fig. B1

Appendix C

The CSS report uses low, medium, and high PEV penetration scenarios to estimate a range of potential futures. These scenarios were estimated as follows:

1. The low penetration scenario is an estimate that is partially based on the EIA AEO 2009 (p. 70) projection of PEV sales (see footnote 20). The EIA AEO 2009 assumes that, in a high oil price scenario, PEV sales grow to approximately 3% of total light duty vehicle sales by 2030 (see footnote 20); the CSS report assumes that PEV sales within each vehicle class rise to approximately 5% of light-duty vehicle sales by 2050, and the

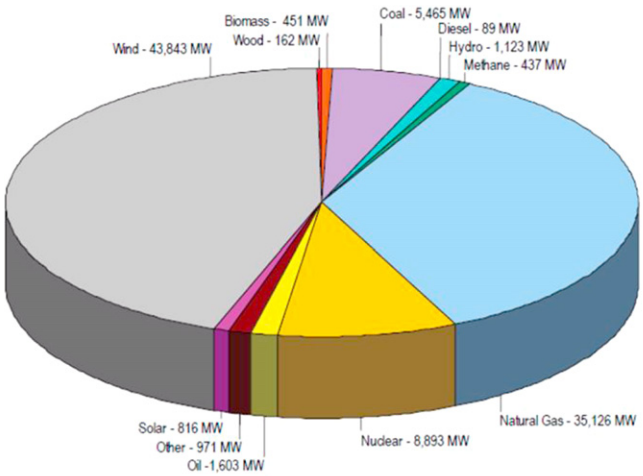

Fig. B1. Types of projects in PJM queue.

specific penetration rates are extrapolated between Year 1 (the first year that a PEV is sold in a specific vehicle class) and 2050, though our model only uses the data through 2030 (see footnote 20).

2. The medium penetration scenario borrows a methodology used in Lemoine et al. (2008) in which the path of PEV sales follows the path of hybrid electic vehicle (HEV) sales (see footnote 20). The CSS report uses nationwide historical and projected HEV sales data, fits that data to a logit sales growth function, and arrives at estimated PEV sales as a percentage of total sales within each vehicle class for each year from 2010 to 2050 (see footnote 20).
3. The high penetration scenario is designed to illustrate maximum possible PEV penetration; this scenario assumes that, based on the number of US households that have the ability to charge at home and the number of vehicles that drive 55 miles per day or less, the maximum possible PEVs as a percentage of new vehicle sales would be 60%. This aggressive-growth scenario also is fit to a logit curve, and it assumes that PEVs rapidly reach the maximum of 60% of sales (within 20 years, as opposed to the medium scenario in which it takes substantially longer to reach the maximum percent of sales). Again, this scenario was designed to estimate an upper-bound of PEV penetration, and penetration rates are calculated for each year through 2050 by vehicle class (see footnote 20).

The penetration rate is applied to each car class beginning in the year in which the CSS report estimated that PEVs of that particular car class will be commercially available. Thus, PEVs in different classes are initially sold in different years, but the penetration growth rates (described in 1–3 above) are applied identically from year 1 of sales in that particular vehicle class through 2050.

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