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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.

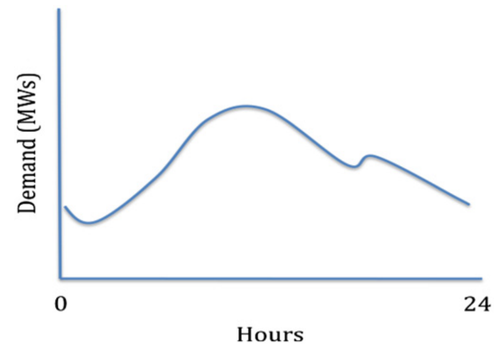

Fig. 1. Daily demand.

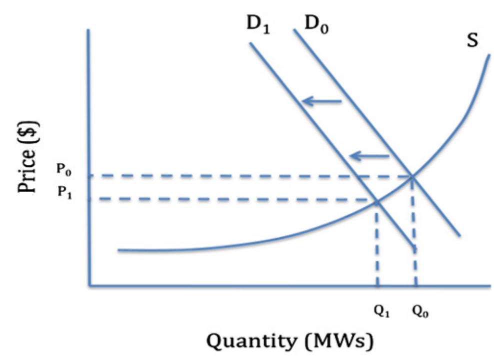

Fig. 2. Supply and demand.

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