Estimating the Impact of Electric Vehicle Charging on Electricity Costs Given an Electricity Sector Carbon Cap

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ABSTRACT

This paper presents results from a model that estimates the short-run effect of plug-in hybrid electric vehicle (PHEV) charging on electricity costs, given a cap on CO_2 emissions that covers only the electricity sector. In the short-run, cap-and-trade systems that cover the electricity sector increase the marginal cost of electricity production. The magnitude of the increase in cost depends on a number of factors including the stringency of the cap in relation to the demand for electricity. The use of PHEVs, which also has the potential to decrease net GHG emissions, would increase demand for electricity and thus increase the upward pressure on marginal costs. The model examines this effect for the New England electricity market, which as of January 2009 operates under the Regional Greenhouse Gas Initiative, a cap-and-trade system for CO_2. The model uses linear optimization to dispatch power plants to minimize fuel costs given inelastic electric demand and constraints on NO_x and CO_2 emissions. The model is used to estimate costs for three fleet penetration levels (1%, 5%, and 10%) and three charging scenarios (evening charging, nighttime charging and twice-a-day charging). The results indicate that PHEV charging demand increases the marginal cost of CO_2 emissions, as well as the average and marginal fuel costs for electricity generation. At all penetration levels the cost increases were minimized in the nighttime charging scenarios.

INTRODUCTION

Anthropogenic greenhouse gas (GHG) emissions are effecting global climate systems and are likely to adversely impact human and environmental welfare if emissions rates are not reduced (1). In order to reduce the negative impacts of climate change, the Obama administration recently endorsed the target of an 80% reduction in U.S. GHG emissions by the year 2050 (2). Since the electric power and transportation sectors are the two largest sources of GHG emissions in the United States, accounting for 34% and 28% of total US emissions respectively (3), significant emissions reductions will need to be made in both of these sectors in order to achieve the overall emissions reductions that the administration has targeted. A cap-and-trade system is one method of reducing GHG emissions in targeted sectors. Every cap-and-trade bill proposed in the 110th Congress included coverage of the electric power sector (4). On the transportation side, current research suggests that plug-in hybrid electric vehicles (PHEVs) have the potential to reduce life cycle GHG emissions (5-9), and the Obama administration has identified PHEVs as a desirable technology for combating climate change and reducing dependence on foreign oil (10). If widely deployed, PHEVs are likely to create significant new demand for electricity and thus their deployment will have important implications for electricity sector cap-and-trade systems.

Cap-and-trade systems can be an effective, economically efficient method of reducing pollutants. Cap-and-trade has been used successfully in the U.S. to reduce SO_2 since 1990 and is currently being used in the European Union to reduce GHG emissions (11). These systems are well suited to situations in which aggregate emissions reductions are more important than geographically specific reductions (12). In addition, transaction costs may be lower when dealing with smaller numbers of large emitters (4). For these reasons, cap-and-trade systems are particularly suited to reducing GHG emissions from the electric power sector. By creating a cost associated with GHG emissions, cap-and-trade systems decrease the economic competitiveness of high GHG intensity fuels, such as coal, relative to lower GHG intensity fuels. Since the cost of the allowances creates an additional marginal cost for power generators, cap-and-trade systems increase electricity prices in the short run. The magnitude of this increase depends on the price of carbon allowances, which in turn depends on the stringency of the cap relative to the demand for electricity as well as on the available generating technologies.

One approach to reducing transportation sector GHG emissions, the transition to vehicle electrification, could have a significant impact on electricity demand and should be considered in conjunction with cap-and-trade systems when assessing the impact of these systems on electricity prices. The price impact may be particularly important when the cap-and-trade system is not economy wide but rather applies only to the electric power sector, as changes in relative energy prices could lead to shifts in the type of energy used in other sectors. Due to cost, infrastructure, and technology constraints, many researchers do not believe that straight electric vehicles are practical mass market vehicles in the near term. Instead, plug-in hybrid electric vehicles (PHEVs), which combine an externally chargeable battery and electric power train with an internal combustion engine for longer range travel, are a more likely intermediary technology on the path to vehicle electrification (13, 14). Currently, several major automobile manufacturers have announced plans to bring PHEVs to the U.S. market (15). Since PHEVs draw a portion of their energy from the electric grid, these vehicles reduce direct emissions from the transportation sector while increasing emissions from the electric power sector. Several recent studies have concluded that this shift is likely to produce a net emissions reduction across both sectors (5-7). These studies found that the magnitude of the GHG reduction depends significantly on the source of electric power generation and that reductions are most significant when electricity comes from sources with low greenhouse gas intensities. Consequently, vehicle electrification is most effective at reducing overall GHG emissions when combined with measures that reduce GHG emissions from electricity generation.

While several researchers have examined the impact of cap-and-trade systems on electricity prices, e.g. (16) for RGGI and (17-20) for the European Union Emissions Trading Scheme, and others have examined the impact of PHEV load on electricity prices (9), the authors are unaware of any published results that estimate the effect of PHEV demand on electricity costs, in the presences of an electricity sector only cap on GHG emissions. This paper presents a model of the impact of PHEV charging on marginal and average fuel costs in the electricity sector given an electricity sector only cap-and-trade program for GHG emissions. Specifically, the model examines this effect in the short-run for the New England electricity market, which as of January 2009 operates under the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade system for CO_2. The RGGI cap-and-trade program covers CO_2 emissions from electricity generation in ten northeastern states. The initial cap set by RGGI was intended to replicate current emissions levels to minimize the immediate impact on electricity prices. Under RGGI the cap will be held constant for the years 2009-2014 and then decrease by 2.5% per year between 2015 and 2018. The model presented here simulates the electricity market at current cap levels and therefore represents price impacts only over the next five year period.

Thus, the goal of this work is to estimate the impact of PHEV charging on fuel costs and CO_2 allowance prices given an electric sector cap-and-trade system. The methods section of the paper describes the model, the data sources and assumptions used to construct it, and the scenarios that were modeled. The model results are presented subsequently, followed by a brief discussion and conclusion.

METHODS

To explore the impact of PHEV electricity demand on marginal fuel costs under the RGGI carbon constraints, we created a short-run, fixed capacity, dispatch model for New England power plants which dispatches power plants to minimize total fuel costs given inelastic electric demand. Least cost production allocation is analogous to a perfectly competitive market with perfectly inelastic demand and is frequently used for modeling the effects of regulation on the electric power sector (21). The resulting supply curve, prior to NO_x or CO_2 constraints, is shown in Figure 1 in the Results section. Dispatch decisions within the model are generated on an hourly basis and the optimal generation from each plant as well as the systemic marginal fuel cost is calculated for each hour of the year. The model was run for a baseline scenario that did not include a carbon cap or demand from PHEVs, a scenario with the RGGI cap but no demand from PHEVs, and nine different scenarios involving the RGGI cap and different levels of PHEV fleet penetration and charging patterns described below.

The model includes the 90 thermal plants in New England with generating capacities of at least 25 MW, the minimum capacity covered under RGGI. Thirteen plants operating on waste fuels (black liquor, digester gas and municipal solid waste), totaling 2,051MW of capacity, were excluded from the model as fuel availability was assumed to be limited by nonmarket factors. The 90 remaining plants had a cumulative nameplate capacity of 31,257 MW. The set of all excluded thermal plants, non-thermal plants, and plants smaller than 25 MW had a nameplate capacity of only 3,479 MW. Transmission constraints, strategic bidding, O&M costs, and ramping time and were not represented in the model.

All power plant data, including heat and emissions rates and generating capacity, are from EPA eGRID for the year 2005, the most current data available from the EPA (22). Hourly demand and fuel cost data are also for 2005 and are from ISO-NE (23) and the EIA (24) respectively. The EIA projects continued growth in electricity demand of approximately 1% per year. However, Ruth et al. (16) argued that demand would decrease under RGGI, due largely to state level investments in energy efficiency programs. Given these conflicting projections, the model used unadjusted hourly demand from 2005.

The model used linear optimization to minimize the fuel costs (used as a proxy for variable costs) of electricity generation in the ISO-NE region (Eq 1) subject to the constraints that supply equal demand for every hour of the year (Eq 2) and that during ozone season, May 1 to September 30, NO_x emissions from plants in Clean Air Interstate Rule (CAIR) states must not exceed the NO_x cap for those states (Eq 3). For all model runs other than the uncapped baseline run, the optimization was also constrained by the requirement that CO_2 emission not exceed the New England allocation of the RGGI CO_2 cap (Eq 4).

$$minimize \qquad \sum_{h=1}^{8760} \sum_{I=1}^{ng} C_{f_{ih}}\, r_{ih}\, G_{ih} \tag{1}$$

$$subject\ to \qquad \sum_{I=1}^{ng} G_i = D_h, \forall\, h \tag{2}$$

$$\sum_{h=2880}^{6552} \sum_{I=1}^{ng} \rho_{NOxi}\, G_{ih} \leq NOx\ Cap \tag{3}$$

$$\sum_{h=1}^{8760} \sum_{I=1}^{ng} \rho_{CO2i}\, G_{ih} \leq C02\ Cap \tag{4}$$

In Eqs. (1)-(4), C_{fih} is the cost of fuel of plant *i* at hour *h* in \$/MMBTU, r_{ih} is the heat rate of plant *i* at hour *h* in MMBTU/MWh, and G_{ih} is the energy output of plant *i* at hour *h* in MWh. D_h is the energy demand in MWh at hour *h*. Time specific demand for PHEV charging was added to baseline demand according to several scenarios described below. The NO_x emissions rate for plant *i* in kg/MWh is given by ρ_{NOxi}. NO_x emissions for plants outside the CAIR region were excluded from the calculation of equation three. The CO_2 emissions rate for plant *i* in kg/MWh is given by ρ_{COxi}.

Additional Demand Due to PHEV Charging

The additional electricity demand created by PHEV charging is a function of the number of PHEVs in operation, the rate and time at which they charge, and the energy required to completely charge each vehicle's battery. We modeled three levels of PHEV fleet penetration, 1%, 5% and 10% of the total New England light duty vehicle fleet. Given a LDV fleet of approximately 11 million vehicles (25), these scenarios correspond to 110,000, 550,000 and 1,100,000 PHEVs operating in New England. The Obama administration has set a target of 1 million PHEVs sales by 2015 (10), while the market research firm Pike Research has projected that total U.S. PHEVs sales are only likely to reach 610,000 by 2015 (26). The middle and high penetration scenarios, therefore, are less likely to occur in the near future in the absence of additional policy measures to promote PHEV sales or significant changes in the prices of batteries, electricity or gasoline.

The authors calculated values for PHEV charging rates, battery capacity and electric drive efficiency from reports on the performance of the Chevy Volt, one of the first PHEVs expected to come to market in the U.S. GM reports that the Volt will be capable of driving 64.4

km on 8.8 kWh of electric energy and will fully charge from a standard 120v outlet in approximately 8 hours (27). This corresponds to a charge rate of 1.1 kW and an electric drive efficiency of 7.3 km/kWh. For other estimates of PHEV performance see (5, 28). Based on this electric drive efficiency and an average annual vehicle kilometers traveled of 20,100 (29), the authors calculated that each vehicle would require, on average, 7.6 kWh of electric energy to completely recharge each day. Given a charger efficiency of 82% and battery charging efficiency of 85% (30), each vehicle would add 10.9 kWh of demand each day. This represents a highly generalized estimate of the energy demand. Actual energy demand will exhibit considerable variation based on in individual driving patterns, variability in PHEV efficiency and other factors including demand for heat and air conditioning. Variability in individual driving patterns and vehicle efficiency are likely to average out somewhat, but heating and air conditioning loads are likely to have distinct seasonal impacts. Since there are very few data available for the additional electric demand in commercial PHEVs that will result from heating and cooling loads, and because this additional load is generally small in traditional vehicles, these seasonal changes in demand have not been included in this model.

With these assumptions, the low fleet penetration scenario of 110,000 PHEVs corresponded to 437,000 MWh of additional demand annually, an increase of 0.33% of the baseline 2005 demand. The medium fleet penetration scenario, 550,000 PHEVs, increased annual demand by 2,188,000 MWh or 1.66% of baseline demand. The high fleet penetration scenario, 1,100,000 PHEVs, increased annual demand by 4,376,000 MWh, a 3.26% increase in demand.

Once the energy required to recharge the battery was calculated, each vehicle was assigned a charging start time for each of three scenarios: evening charging, delayed nighttime charging and twice-a-day charging. Table 1 summarizes the fleet penetration and charging scenarios modeled for this paper.

TABLE 1 PHEV Penetration Scenarios Modeled

Scenarios		PHEV Fleet Penetration	Added Demand	Charging Scenario
Baseline – No Cap	(B_0)	0%	N/A	N/A
Baseline – RGGI	(B_R)	0%	N/A	N/A
Low	(L_1)	1%	0.33%	Evening Charging
	(L_2)	1%	0.33%	Delayed Charging
	(L_3)	1%	0.33%	Twice a day
Medium	(M_1)	5%	1.66%	Evening Charging
	(M_2)	5%	1.66%	Delayed Charging
	(M_3)	5%	1.66%	Twice a day
High	(H_1)	10%	3.26%	Evening Charging
	(H_2)	10%	3.26%	Delayed Charging
	(H_3)	10%	3.26%	Twice a day

In the evening-only scenario vehicles charge once per day starting at 6, 7 and 8 PM. In the delayed nighttime charging scenario vehicles charge starting at 10 pm, 11 pm and 12 am. In the twice-a-day scenario, vehicles charge both in the morning and evening starting at 8, 9 and 10 AM and 6, 7 and 8 PM. In this last scenario, each vehicle consumes 5.45 kWh, half of its total daily demand, in both the evening and morning hours. In all three scenarios, the vehicles were evenly distributed among the three start times and charged continuously until completely recharged. Similar charging scenarios have been modeled in a variety of other PHEV impact studies (9, 30, 31). A number of PHEV impact studies also modeled "optimal" charging scenarios, in which PHEV charging is coordinated with electric utilities to minimize the impact of vehicle charging. While communication between the utilities and PHEVs may make optimal charging possible, the authors assumed that this practice would not be widespread in the short-run and did not model this charging scenario. Modeling alternative charging patterns remains for future work. Information on alternative charging patterns can be found in (32-34).

RESULTS

The model results showed that instituting a carbon cap caused an increase in marginal and average fuel costs and that additional demand from PHEVs exacerbated these increases as well as increasing the cost of CO_2 emissions relative to the baseline capped case. These results were true at all penetrations levels and in all charging scenarios and, as expected, were largest in the high fleet penetration case and lowest in the low fleet penetration case. In addition, as expected, the nighttime charging scenarios consistently had the lowest impact on costs of any of the charging scenarios. The baseline supply curve is shown in Figure 1, below.

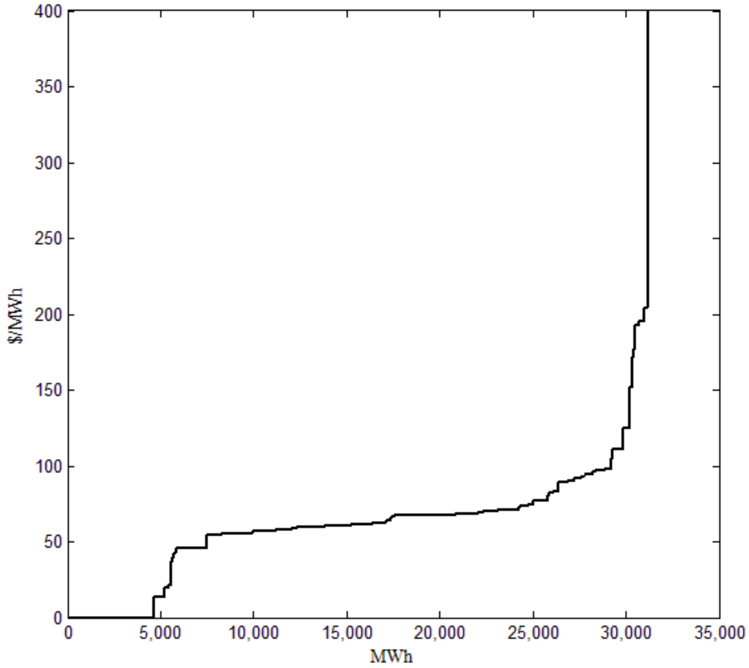

FIGURE 1 Baseline Supply Curve .

The impact of each of the three charging scenarios on daily electricity demand is shown below in Figure 2. The high fleet penetration case is shown since this case illustrates where PHEV load is added to the baseline demand with the greatest visual clarity. Charging scenarios 1 and 3, evening charging and twice-a-day charging, increased peak demand on both summer and winter days. Charging scenario 2, delayed nighttime charging, did not impact peak demand in either season.

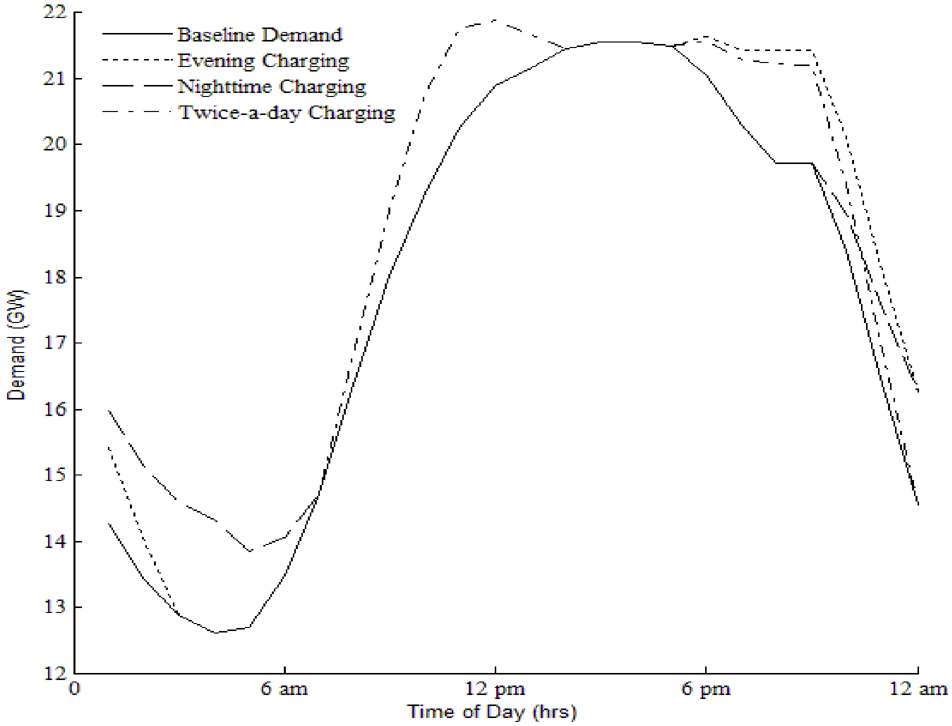

FIGURE 2 Electricity demand curves. The solid line shows baseline electricity demand from August 22, 2005 in GWs. The dashed lines show the new electricity demand with 10% PHEV fleet penetration under a variety of charging scenarios.

Figures 3 and 4 show the estimated impact of PHEV electricity demand on average fuel costs and marginal fuel costs, respectively. These results reflect the additional costs associated with added demand and the costs associated with the fuel switching necessary to remain under the cap. In all cases, the price increase was greatest in the twice-a-day charging scenario and lowest in the delayed charging scenario.

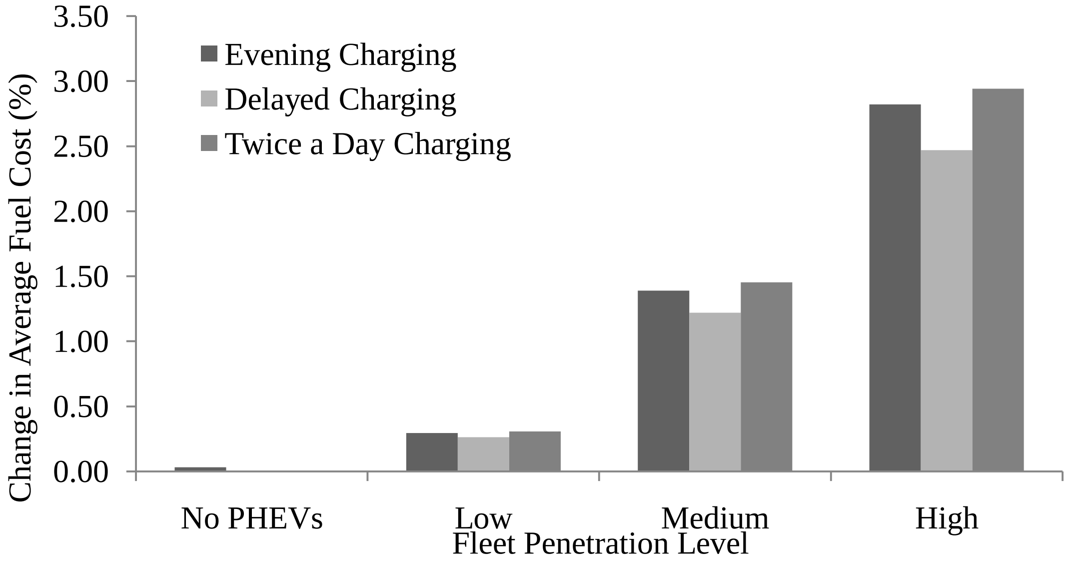

FIGURE 3 Estimated change in average fuel costs under various PHEV charging scenarios.

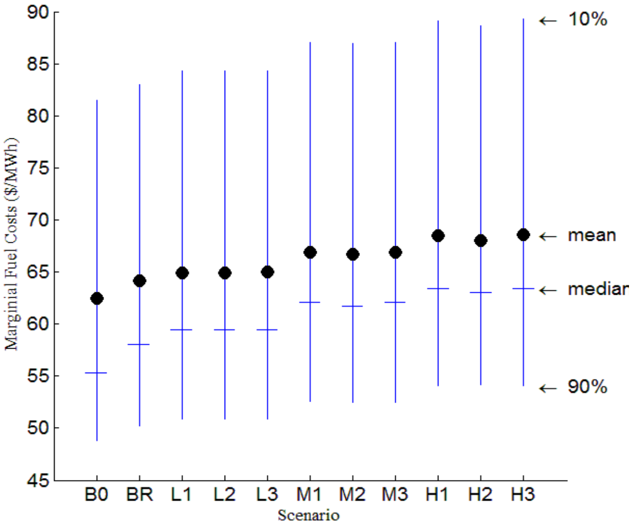

FIGURE 4 Distribution of marginal fuel costs for each of the modeled PHEV charging scenarios.

Due to the exclusion of O&M costs and other dispatch and transmission considerations from the model, the marginal costs calculated in the model are lower than the wholesale electricity prices in the ISO-NE market. The average marginal cost in the uncapped baseline scenario was \$62.47/MWh while the average marginal cost for ISO-NE in 2005 was \$76.64/MWh.

Figure 5 shows the cost per ton of CO_2 emissions in each of the scenarios where CO_2 emissions were assumed to be equal to the shadow price for CO_2, calculated as the value of the Lagrange multiplier that satisfied the CO_2 constraint given in equation 4. The baseline CO_2 price projected by the model, \$3.40 per ton, is closely in line with the market price for RGGI allowances. Through the first four auction rounds, 2009 allowances have ranged in price from

$3.07 to $3.51 per ton (35). Charging scenario 2, delayed nighttime charging, caused the smallest increase in costs. In both the high and low penetration scenarios, twice-a-day charging had the largest impact on costs. In the medium penetration case, evening and twice-a-day charging had an equal effect on costs.

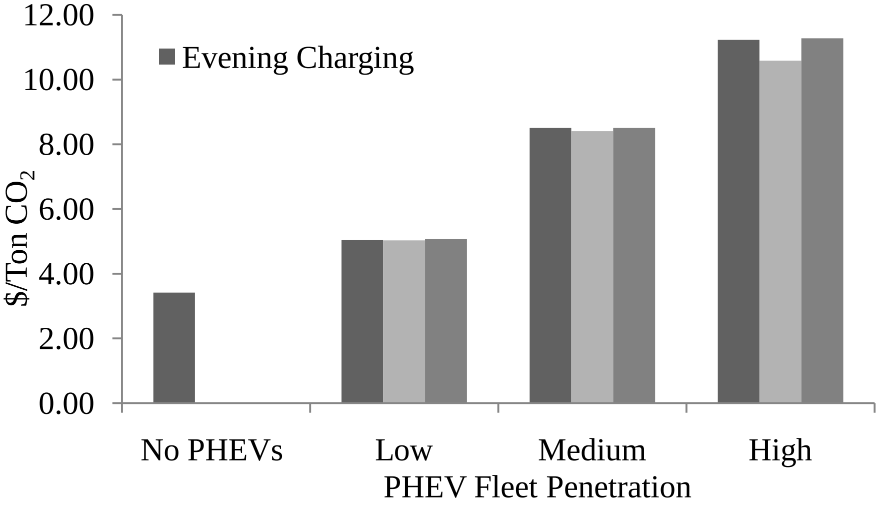

FIGURE 5 Carbon price in $/Ton CO_2 for all PHEV charging scenarios.

Total regional CO_2 costs in the baseline RGGI scenario are $172 million. Assuming nighttime charging, which minimizes CO_2 costs, this cost rises to $255 million with 1% PHEV penetration scenario, $425 million with 5% PHEV penetration scenario and $535 million with 10% PHEV penetration. The deployment of 550,000 PHEVs, 5 % penetration, therefore, increases CO_2 costs by $253 million over the baseline, or approximately 0.19 cents per KWh.

DISCUSSION

The model results demonstrate a clear positive relationship between PHEV driven electricity demand and increased fuel and CO_2 costs when electricity sector carbon emissions are capped. This impact is greatest when charging takes places during times of high demand, the morning and evening, likely reflecting that a greater proportion of total generating capacity must be dispatched to meet demand which reduces the overall plant dispatch flexibility relative to periods of lower demand. As modeled here, nighttime charging had the lowest impact on generating costs. Several other studies have found that nighttime and off-peak charging would have substantial benefits to both grid operators and consumers (8, 32). The results presented here support these earlier findings.

The model described in this paper estimates the short term impact of PHEV charging on electricity generating costs. Because the focus is on short-run effects, several factors could alter the outcomes from those described here. Changes in the generating mix through new plant construction and/or plant retirement would change the basic underlying supply curve and thus change the optimal dispatch order and, consequently, electricity prices. Given the relatively long period of time required to for power plant permitting and construction, significant changes in the generating mix are unlikely to occur in the 2009 – 2014 cap period modeled in this paper. In addition, significant changes in relative fuel prices could also alter the least cost dispatch order and change the marginal cost of generation. Though these changes could change the specific impact of PHEV demand on generating costs, the relationship between increased demand and increased fuel and emissions cost is unlikely to change in the near term. In future work, the authors expect to model the effect of alternative generation mixes on the trends observed in this paper.

CONCLUSION

Several studies have demonstrated the potential for PHEVs to reduce overall emissions across the electricity and transportation sectors. The results presented here show that PHEV demand would increase CO_2 emissions allowance prices when the electricity sector has a GHG cap but the transportation sector does not. In this case, switching energy consumption from the liquid fuels sector to the electricity sector, as occurs with PHEV deployment, simultaneously reduces overall CO_2 emissions and drives CO_2 allowance prices up in the electricity sector. In the model described here, a 5% deployment of PHEVs would increase the price of CO_2 allowances from $3.4/ton to $8.4/ton, increasing electricity costs for all electricity customers, not merely PHEV owners.

These results indicate that an electric sector only cap, such as RGGI, increases the total social cost of potentially environmental beneficial fuel switching from gasoline toward electricity. This increased cost is born by both PHEV owners and other electricity users. The aggregate impact on electricity costs is substantial. In the 5% fleet penetration scenario, the introduction of PHEVs increases CO_2 costs $253 million and average fuel costs by approximately 3%. Additionally, though the effect is relatively small with the cap level modeled here, these effects also increase the operating cost for PHEVs. Assuming the 0.19 cents per KWh rise in electricity prices due to increased CO_2 prices calculated for the 5% penetration scenario and 10.9 kWh of electricity consumed each day, this adds less than $8 a year in operating costs. However, these results would be more pronounced with a more stringent cap or higher vehicle penetration levels.

Further research and model runs could assess the sensitivity of these results to changes in car charging parameters, relative fuel prices, differing generating mixes, and varying cap levels. Additionally, since O&M cost vary considerably by plant type, including O&M costs in future work would also refine the accuracy of the model outputs.

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