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Evaluating the Impact of Plug-in Hybrid Electric Vehicles on Regional Electricity Supplies

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Abstract

Plug-in Hybrid Electric Vehicles (PHEVs) have the potential to increase the use of electricity to fuel the U.S. transportation needs. The effect of this additional demand on the electric system will depend on the amount and timing of the vehicles' periodic recharging on the grid. We used the ORCED (Oak Ridge Competitive Electricity Dispatch) model to evaluate the impact of PHEVs on the Virginia-Carolinas (VACAR) electric grid in 2018. An inventory of one million PHEVs was used and charging was begun in early evening and later at night for comparison. Different connection power levels of 1.4kW, 2kW, and 6kW were used. The results include the impact on capacity requirements, fuel types, generation technologies, and emissions. Cost information such as added cost of generation and cost savings versus use of gasoline were calculated. Preliminary results of the expansion of the study to all regions of the country are also presented.

The results show distinct differences in fuels and generating technologies when charging times are changed. At low specific power and late in the evening, coal was the major fuel used, while charging more heavily during peak times led to more use of combustion turbines and combined cycle plants.

Introduction

Hybrid vehicles have been touted as one of the best methods to improve gasoline mileage, by using a combination of a gasoline engine and batteries to provide vehicle power. One current limitation is that all energy must initially come from the gasoline engine, limiting the energy source to expensive and insecure oil supplies. A common thought is to allow the owner to recharge the batteries from the electric grid, opening up a number of other energy sources for our transportation needs. These plug-in hybrid electric vehicles could provide the fuel flexibility and clean operation associated with batteries and the electric grid plus the higher range and rapid refuel capabilities associated with gasoline engines.

There has generally been the expectation that the grid will not be greatly affected by the use of the vehicles, either because the recharging would only occur during offpeak hours, or the number of vehicles will grow slowly enough that capacity planning will respond adequately. But this expectation does not incorporate that end-users will have control of the time of recharging and that many customers will choose to plug in when convenient for them, rather than when utilities would prefer. The call for power from vehicles could be anytime during the day with a peak in the late afternoon rather than only during the offpeak time.

It is important to understand the ramifications of introducing a number of plug-in hybrid vehicles onto the grid. Depending on the time and place of the vehicle additions, they could cause local or regional constraints on the grid. They could require the addition of new electric capacity, increase the utilization of existing capacity, or a mixture of both. Reserve margins could be reduced if capacity does not keep up with the added demand, with resulting reliability concerns. Local distribution grids will see a change in their utilization pattern, and some lines or substations may become overloaded sooner than expected.

Using grid-supplied electricity will shift the location and change the quantities of any emissions from just tailpipes to a mixture of tailpipes and power plants. With power plants being a more tightly regulated source, plug-in hybrids could bring more of the country's transportation-related emissions under stricter regulation. With emission caps in place for key pollutants from stationary sources, a displacement of gasoline with electricity generation will mean an overall reduction in emissions. It will be important to look at the combined system to evaluate the net effect on emissions. This paper is based on an earlier paper from ORNL (Hadley 2006).

Plug-in Hybrid Characteristics

Vehicle characteristics

There are a number of hybrid vehicles available in the U.S. currently, however none of these have plug-in

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capability. These vehicles have battery capacities of 1-2 kWh and can only travel on battery power a few kilometers at relatively low speed. The batteries are rarely heavily discharged and used more to recover braking energy and provide supplemental power boosts. Battery technology advances are required before PHEVs can become economically viable. Higher capacity batteries with deeper discharge capability would allow the vehicle to travel further on battery power. Various proposals include distances of 20, 40, or 60 miles using battery only. There are further permutations on whether a vehicle would run solely on battery until a discharge level was reached and then use a combination of the engine plus battery as in current hybrids, or whether the car would use both engine and battery from the start in order to optimize battery life. In addition, allowing the vehicle to run at highway speed solely on battery power requires a more powerful electric motor that increases the cost of the vehicle.

If solely the battery is used until a preset discharge level is reached, then batteries are likely to be more thoroughly discharged upon the completion of their trips, thereby allowing more energy to be delivered from the grid rather than gasoline. 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. It would require knowledge of the relative cost of gasoline and electricity, battery lifespan reduction from increased discharge, cost of the battery replacement, vehicle performance requirements, emissions restrictions, etc. The objectives and constraints could conceivably be different for each owner, and vehicle manufacturers will likely only be able to provide limited alternatives, but these alternatives could have a large impact on the charging requirements of a PHEV.

Charging characteristics

A key factor to understand about PHEV is that the power demand on the grid will be a function of the voltage and amperage of the connection to the grid. The capacity of the battery will then determine the length of time it will take to recharge the battery, given the connection strength.

EPRI has conducted several studies on PHEV capabilities and issues. One presentation by Dr. Mark S. Duvall at the DOE Plug-in Hybrid Electric Vehicles Workshop provided several characteristics for evaluating PHEV impacts on the grid (Duvall 2006). As the presentation shows, there are an array of options for the connection between the vehicle and the grid. At 120 volts AC, a 15 amp circuit would be about a 1.4 kW load, while a 20 amp circuit would be about 2.0 kW. If the user instead uses a 208/240 volt and 30 amp circuit, then the load could be as much as 6 kW.

A comparison of time required for recharging is given in Table 1. This table, from the Duvall report, shows the amount of time for vehicles that have a 20-mile battery range (PHEV 20) to recharge from 20% to 100% of State of Charge (SOC). Larger battery packs (longer distance) would increase the time required while higher voltage or amperage would reduce the time.

Table 1. Charging requirements for PHEV-20 vehicles (Duvall 2006)

PHEV 20 Vehicle	Pack Size	Charger Circuit	Charging Time 20% SOC
Compact Sedan	5.1 kWh	120 VAC / 15 A	3.9 – 5.4 hrs
Mid-size Sedan	5.9 kWh	120 VAC / 15 A	4.4 – 5.9 hrs
Mid-size SUV	7.7 kWh	120 VAC / 15 A	5.4 – 7.1 hrs
Full-size SUV	9.3 kWh	120 VAC / 15 A	6.3 – 8.2 hrs

1.2 – 1.4 kW power, 1 or 2 hours conditioning

Using the average number of hours times a power level of 1.4 kW, the amount of energy needed and schedule for recharging each PHEV would be approximately as in Table 2. The total energy in is higher than the battery capacity because of energy losses and power variations, with an average loss of ~15%.

Table 2. Power requirements (kW) by hour for PHEV-20 vehicles at 120V / 15A

Hour	1	2	3	4	5	6	7	8	Total kWh
Compact Sedan	1.4	1.4	1.4	1.4	0.91	0	0	0	6.51
Mid-size Sedan	1.4	1.4	1.4	1.4	1.4	0.21	0	0	7.21
Mid-size SUV	1.4	1.4	1.4	1.4	1.4	1.4	0.35	0	8.75
Full-size SUV	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.35	10.15

Assuming a constant energy requirement for fully charging the battery, higher voltages or current would shrink the time required to fully charge, as shown for mid-size sedans in Fig. 1. The actual demand curves would vary more as the battery approached full charge and be dependent on other factors. Any battery charging will vary the amperage as the battery approaches full state of charge, such that the power needs will fluctuate and tail off towards the end of the charging time. This is approximated in the table and calculations by having the last hour being only a partial charge. Our analysis only requires hourly values to match against hourly utility demand levels, as discussed below.

Many cars will not be fully discharged (at 20% SOC) at the time they are plugged in. Also, the owners may need to unplug them for travel before they are fully charged. These added complications are important, but will not be considered in this preliminary analysis.

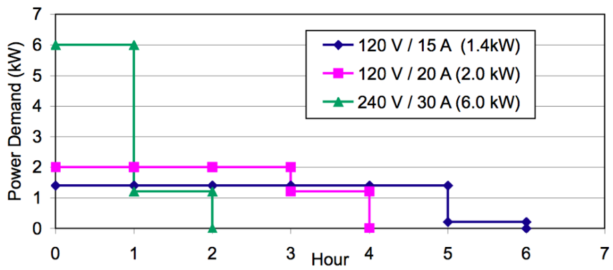

Fig. 1. Hourly demand for PHEV-20 mid-size sedan at different voltages and currents

Timing of plug-in

A key question is when would consumers recharge their vehicles? The optimum time for electricity providers is typically at night when demand is low and low-cost plants are the marginal producers. Any additional generation would come from these low-cost plants and not strain the existing transmission and distribution (T&D) system. However, for consumers the preferred time (absent any incentives to change their preference) is likely to be as soon as they are within easy access to a plug. This both is most convenient since they are at the vehicle already, and also improves their options since they may need the vehicle soon and would prefer a more fully charged battery.

There are various options for utilities to modify customer choices, including pricing schemes favoring nighttime charging or regulatory fiats on vehicle charging. Technically, it may be through smart chargers that know the price of power and/or driving habits of the owner. Such questions are fertile areas for more extensive analysis but are beyond the scope of this paper.

Other charging patterns may be for consumers to recharge at their place of work or shopping, giving them additional range. Employers may offer such options as benefits to employees or local governments may offer this to reduce afternoon air pollution levels (since battery power would then be used more on the trips home.) The utility and businesses could even install the infrastructure to allow consumers to plug in anywhere and have the cost of purchased power added to their bill.

There is also the concept of allowing the vehicles to provide power from their engines or batteries to feed the grid at times of peak demands. Further analysis is needed on the cost to consumers, the electric provider, and the environment by allowing this. It may be that operating the vehicles to provide electricity to the grid may be more expensive and dirtier than building additional power plants.

Regional Grid Analysis

Given that the PHEVs would have charging characteristics as shown above, what would be the impact on a region's electrical demand? Several factors must be considered: the number of vehicles, their charging pattern, other electrical demands on the region, and the generating supply.

In the spring of 2006 a group under the guidance of Robert Imhoff of Baron Advanced Meteorological Systems simulated the energy supply regions of VACAR (South Carolina, North Carolina, and much of Virginia), Southern (Georgia and parts of Alabama, Mississippi, and northern Florida), and TVA (Tennessee and parts of Kentucky, Mississippi, and Alabama). These are all sub-regions in the Southeast Electric Reliability Council (SERC) that coordinates the electric power systems for the region (Fig. 2). Our analysis simulated the power supply and demand for each subregion in the year 2018. (Imhoff et al. 2006)

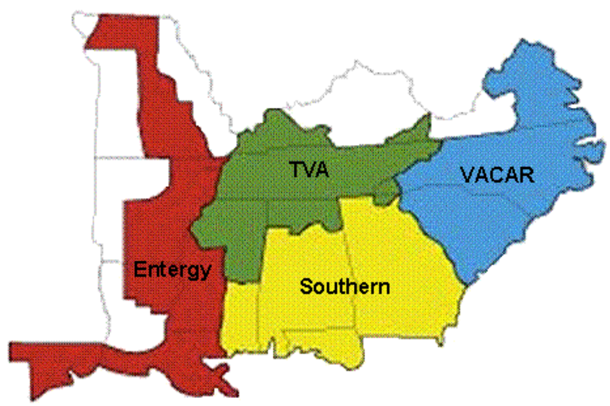

Fig. 2. Southeast Electric Reliability Council Sub-regions

A detailed analysis, focused on the power supply and demand in the VACAR subregion, is reported here along with a preliminary analysis for other regions of the country.

PHEV Market

What could be the possible number of PHEV on the road in 2018 in the VACAR region? First, what is the projected market share and how will this grow? According to the Duvall report, PHEV-20 vehicles have a base case market potential of over 25% of sales for the entire car and light-truck market regardless of commute distance. Of course, the actual penetration will depend on a number of factors that are unknown yet, but as an assumption we used a gradual ramp-up of market share from 0% in 2010 to 25% in 2018 (Fig 3).

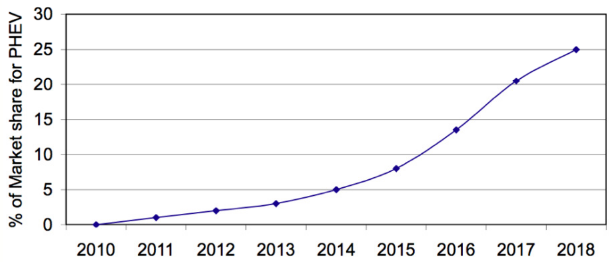

Fig 3. Possible increase in market share for PHEV-20 vehicles

Next, it was necessary to calculate the sales volume for all vehicles in the region over this time. Kiplinger provides a list of the annual sales for cars and light trucks in the U.S. from 1985 to 2006 (Kiplinger 2006). For 2007 on, we used a value of 17 million vehicles, increasing by 1% per year (Fig. 4). To find the number of sales in the VACAR region, we looked at the ratio of vehicle registrations in North Carolina, South Carolina and Virginia compared to the national total. According to the Bureau of Transportation Statistics, registrations for automobiles, pickups, vans, and SUVs totaled 15.3 million in those states and 224.3 million in the entire country, giving a ratio of 6.8% (BTS 2005).

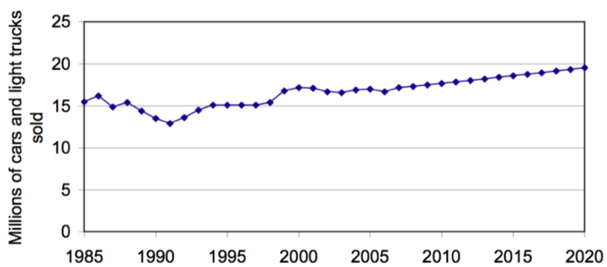

Fig. 4. Past and projected vehicle sales in the U.S.

Multiplying each year's market share for PHEV by the national sales amount and 6.8% gives the annual sales of PHEV in these states. Assuming that the vehicles are not retired before 2018, the sum of these values gives an estimate of the number of PHEV on the road in 2018, and works out to one million vehicles. Also using the registration amounts for the country, we find that the ratio of automobiles to all types of vehicles (autos, light trucks and SUVs) is 60%. For our analysis we assumed the amounts were equally split between compact and mid-size sedans (30% each) and mid-size and full-size SUVs (20% each). These values could be refined if further analysis is needed.

Applying these percentages to the number of vehicles and charging schedule gives a system demand schedule as appears in Fig. 5. These curves assume that all of the vehicles are plugged in at the same time. The curves change as owners spread out the timing of their initial plug-in. Figure 6 shows the curves if half of the owners plug in at the start and the other half begin charging one hour later.

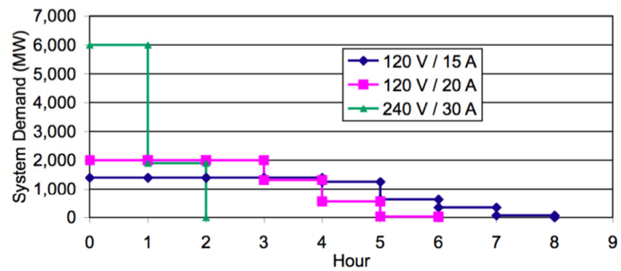

Fig. 5. VACAR system demand from all PHEV charging at once

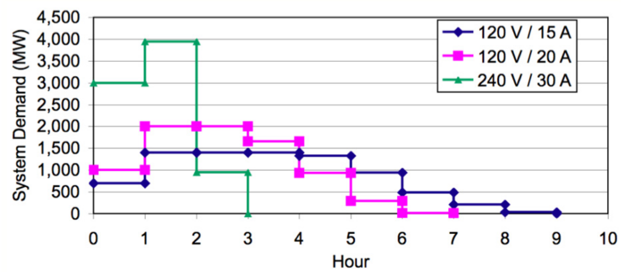

Fig. 6. VACAR system demand if half of PHEV charge one hour later

Regional Supply and Demand

The ORCED model uses the collection of available electricity supply sources to dispatch plants to meet the defined demands for a single year of operation (Hadley and Hirst 1998). The ORCED version used for the VACAR region models a single region without internal transmission constraints. It can handle several thousand power plants and models two seasons, peak and off-peak.

The model was developed at Oak Ridge National Laboratory to examine numerous facets of a restructured electricity market. ORCED is focused on power generation for a region, but it also calculates a number of key financial and operating parameters. Several versions of the model have been developed over the years depending on the needs of the study. Its flexibility allows it to answer many different questions concerning the electric utility industry.

There are two main preprocessing steps necessary for initiating the model: estimation of demand and estimation of supply. The model then matches the supply to demand based on the cost and other parameters in a simulation of how utilities dispatch the fleet of plants available.

Demand Simulation Demands are estimated by first finding the hourly demands for the region of study. Many utilities have to submit their hourly loads to the Federal Energy Regulatory Commission. Hourly demands for each control area for 2005 and earlier years can be found on the FERC website. (FERC 2005) To determine the hourly loads for the VACAR region we combined the hourly loads from 2003 for Duke Power, Carolina Power & Light, the South Carolina Public Service Authority, South Carolina Electric & Gas, and the Old Dominion Cooperative (Virginia portion). We then adjusted the totaled amount to match reported VACAR total for 2003. A further adjustment was made that increased the total to match expected load growth to 2018 according to projections from the Energy Information Administration's Annual Energy Outlook 2005. (EIA 2005).

Each hour's demand can be multiplied by the adjustment factors to find a representation of the hourly load profile for 2018 (Fig. 7). While using the 2003 curves as a template may cause a distortion because each year has its own weather patterns and consequent load shape, the 2018 pattern is unknown so 2003 may be as representative as any other year.

After the hourly demands are found for the sub-region, they must be converted into load duration curves for the peak and off-peak season (Fig. 8). The load duration curve (LDC) reorders demands by increasing power levels and so shows the percent of time that demand equals or exceeds a given power level. For example, demands exceed 65 GW for 100% of the time, but 140 GW only 14% of the peak season and 1.6% of the off-peak season. Separate curves were developed for peak and off-peak seasons to determine power plant production in each season.

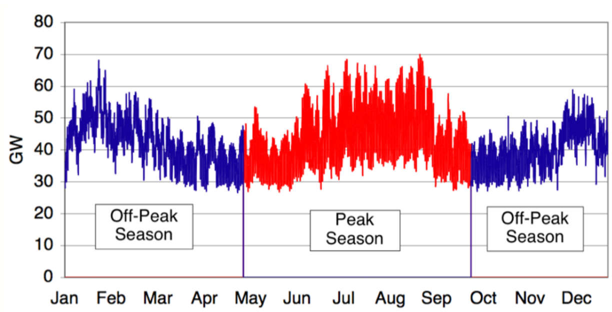

Fig. 7. Projection of hourly loads for the VST region in 2018

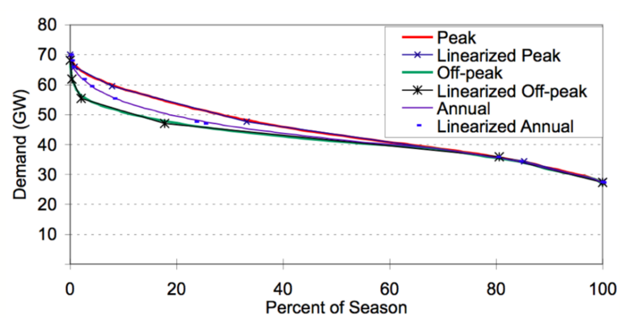

Fig. 8. Load Duration Curves for VACAR region in 2018

Supply Simulation Supply is found by getting the list of plants for the defined region from several databases, including EIA's database for use within NEMS, EPA's eGRID and NEEDS databases, and the dataset created by the Integrated Planning Model (IPM) run used for the Visibility Improvement State and Tribal Association of the Southeast (VISTAS). The most complete set of power plants is from the EIA NEMS dataset. However, this list only includes known plants within the region. There are expected to be a number of plants built between now and 2018. The VISTAS Phase II IPM run includes these plants, with a contractor assigning locations for them in the region. These were added to the dataset, while some plants that the VISTAS dataset did not have were removed. For this study we also added 1200 MW of additional capacity above the VISTAS amount to improve the reserve margin for the region. This resulted in a list of around 760 power plant units in the VACAR subregion. The summed nameplate capacities of each type of plant are shown in Table 3.

Table 3. VACAR 2018 power plant capacities

Plant Type	Capacity (MW)
Oil Combustion Turbine	1184
Gas Steam Turbine	133
Gas Combustion Turbine	8,353
Gas Combined Cycle	9,180
Coal Low Sulfur	575
Coal Medium Sulfur	5,575
Coal High Sulfur	2,901
Coal Scrubbed	24,012
Renewable	359
Nuclear	17,722
Hydro	3,311
Pumped Storage	4,589
Total	77,893

Changes in Demand

As shown in Fig. 5, regional demand could increase by 1400 to 6000 MW with the number of vehicles projected, depending on the type of connection and timing. For our initial analysis, we will assume that vehicles use the medium power level (120 V / 20 A, 2 kW/vehicle) and split their initial charging between two hours. One scenario will have half plugging in at 5 p.m. and half at 6 p.m. weekdays. The second scenario will have half plugging in four hours later at 9 p.m. and half at 10 p.m. weekdays. We will ignore the weekends and partial plug-in times for this analysis.

Effect of Changing Charging Time Starting with the Base hourly demand described above, we added the demand if the PHEVs were plugged in during the early evening (Fig. 9) or night (Fig. 10). These figures show the hourly loads for representative weeks in each of four months: January, April, July, and October. Note that PHEV demand affect the peaks most frequently in the April and October weeks. Winter peaks occur mostly in the morning, while summer peaks are in mid-afternoon. Also, these spring and fall weeks have much lower overall demands, since heating and cooling needs are modest.

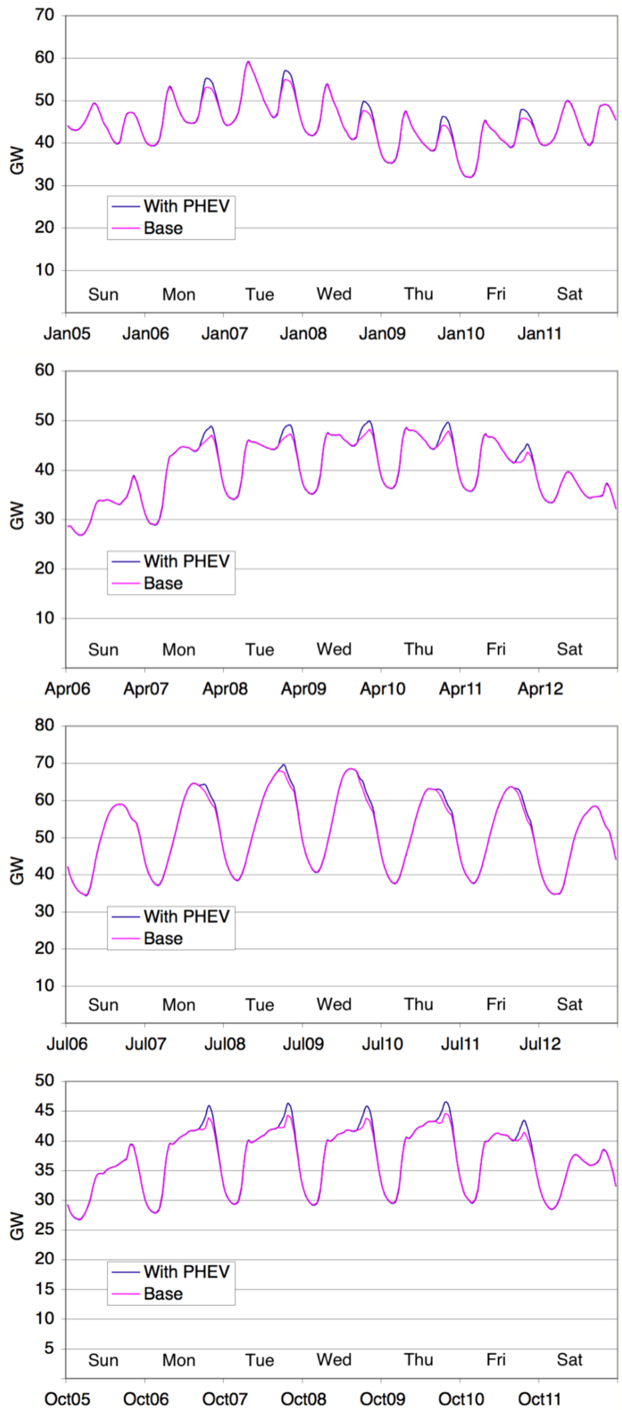

Fig. 9. VACAR 2018 system demand (4 typical weeks) with evening charging of PHEV

The nighttime charging scenario has the demand being added while overall demands are dropping so have little effect on peak capacity needs. Later charging times would shift the demands even further into the valley of the load curves, when the lowest cost plants are operating. (The National study described at the end of this paper used a nighttime charging starting one hour later.)

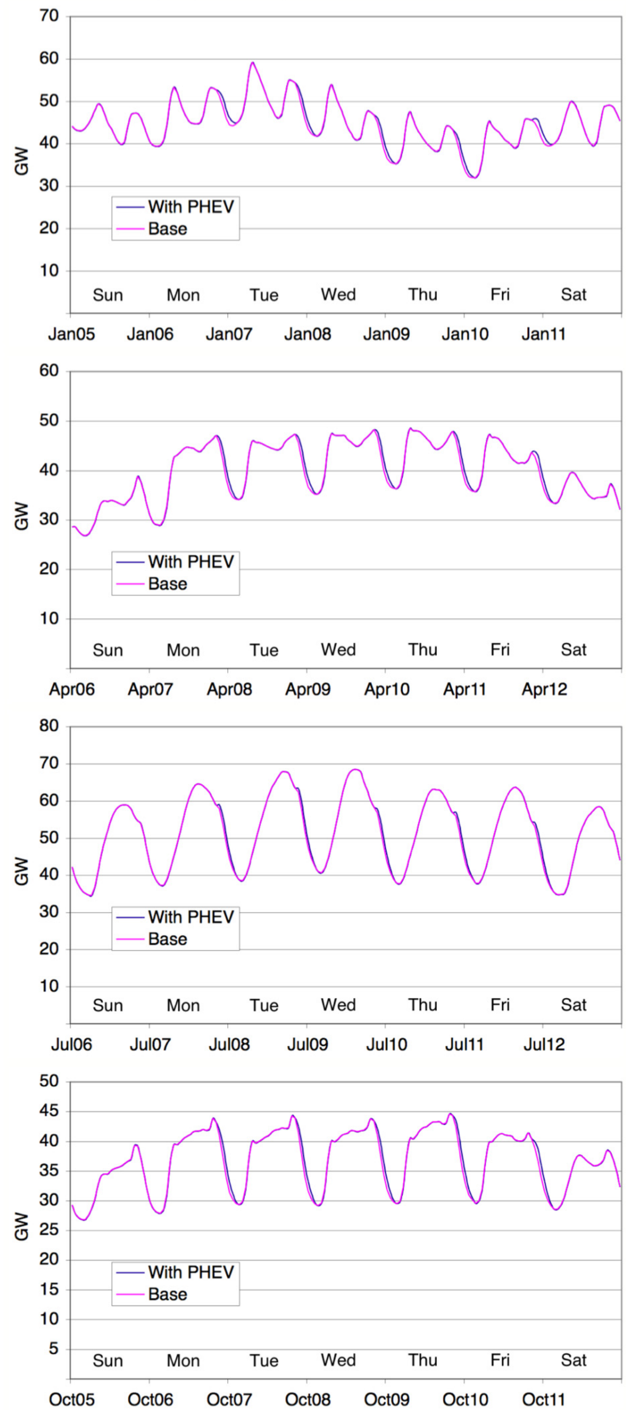

Fig. 10. VACAR 2018 system demand (4 typical weeks) with nighttime charging of PHEV

Effect of Varying Charging Level The curves above are based on a maximum demand of 2 kW per PHEV. Using the lower range of 1.4 kW/vehicle would lessen the peak, and stretch the demand further into the valley of the load curve. Alternatively, if the PHEV were to charge using a 208/240 V connector at 30 Amps, similar to the connection for an electric clothes dryer or stove, then the rise in demand would be higher and shorter. Figure 11 shows the July curve for all three power levels using the early evening charging cycle. On certain days, the loads can significantly increase the daily peak, especially if vehicles charge at 6 kW apiece.

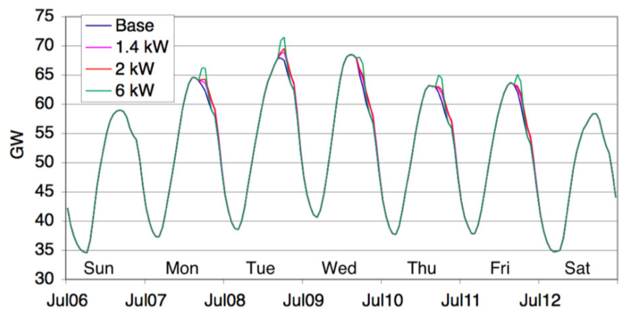

Fig. 11. July 6-12 hourly demand with PHEV charging in early evening at 1.4, 2, and 6 kW/vehicle

Impact on Supply

Given the change in demand, how does this change the production of power? Using the list of power plants for the VACAR region in 2018, it is possible to dispatch the plants to meet the demands using the ORCED model. The change in production between the base scenario and one with PHEV will show what plants raised their production to meet the increased demand. Figure 12 shows the relative amounts of power from the main types of power plants. In all cases, the total added production was 2,060 GWh for these 1 million PHEVs.

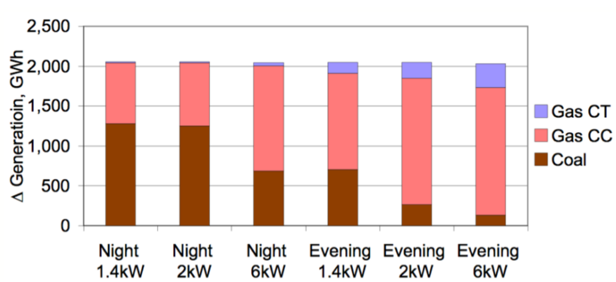

Fig. 12. Generation shares by plant type for PHEV charging level and timing

From the figure, it is clear that in most cases the plants on the margin in the early evening are gas combined cycle and turbines. The evening scenario with 6 kW charging, which has all of its effect in the early evening, has over 90% of the generation coming from these plants. The 2 kW and 1.4 kW charging scenarios spread the production into the later evening when coal power is more often the marginal producer. The nighttime charging scenarios further exemplify this effect, with over 60% of the added generation coming from coal. The nighttime charging at 6 kW results are interesting compared to the Evening 2kW scenario in that the timeframe for charging is still largely dominated by combined cycle plants, but with few combustion turbines in use; instead, coal production supplies the power in the later hours.

Impact on Emissions and Cost

With the change in fuel source for the 20 miles that the batteries provide off of the grid, there will be a change in the amounts and distribution of different pollutants. Assuming an efficiency of 40 mpg for the engine-derived power for the vehicle, \$3/gallon for gas, and 0.05 g/mile of NOx, 1 million vehicles operating for 261 days/year would translate into the values shown in Table 4. The alternative of operating 1 million PHEV in VACAR using the Evening charging at 2kW scenario are also shown.

Table 4. Added fuel use, emissions, and cost of operating one million gasoline vs. PHEV using the Evening charging at 2 kW scenario

Parameter	Gasoline-fueled Miles	Electricity-fueled Miles
Fuel use	311 thousand barrels of gasoline	13.9 billion cu feet of natural gas 147 thousand short tons of coal
Carbon emissions	312 thousand metric tons of carbon	283 thousand metric tons of carbon
NO_X emissions	261 metric tons of NO_X	900 metric tons of NO_X (0 tons with cap)
SO_2 emissions	0	2.6 thousand tons of SO_2 (0 tons with cap)
Cost	\$391 million in gasoline	\$105 million in added electricity generation cost

The carbon emissions are lower using electricity rather than gasoline. The NO_X and SO_2 amounts show up as higher, but are based on the idea that utilities are free to emit what the plants produce. In actuality, the utilities are subject to caps in their emissions so increases in one area must be offset by reductions elsewhere, or pollution control equipment must be used more so that total emissions are unchanged. In that case, the added emissions of NO_X and SO_2 would be zero. It should be noted that 70% of the NO_X and all of the SO_2 is from the coal plants dispatched. These would be the most expensive and least efficient coal plants (highest marginal cost), which may be why emissions are so high.

The \$105 million in added generating cost is based on the variable cost (fuel and operations) for the power plants. At 2060 GWh of power, this has an average cost of 5.1 ¢/kWh. Even if customers paid twice this for power, it would still be roughly half the cost of the avoided gasoline purchases. So even if PHEV charging is done during peak hours, the cost is lower than using gasoline instead. Drivers would almost always have a financial incentive to recharge their batteries rather than use gasoline. This also brings into question the value of using PHEV to provide power to the grid.

Impact on Generation Adequacy

With an increase in demand, if the supply is not increased then the potential for inadequate amounts of generation increase, even if the demand does not occur exactly during the peak demand time. This is because there is the probability that one or more plants will be out of service when demand is approaching the peak and so capacity is insufficient. The utility industry uses a parameter called the Loss of Load Probability (LOLP), which defines the likelihood that generation amounts will not be sufficient to meet demand. The ORCED model uses a probabilistic method that calculates the LOLP for each of the demand periods and for the year as a whole.

In the Base scenario without any PHEV, the LOLP for the year was 0.167% or 6.1 days in ten years. For all scenarios the values are shown in Table 5. In each PHEV scenario, the LOLP is higher than the base, with those with charging in the evening having a higher value because the added demand happens when demand is nearer the daily peak.

Table 5. Loss of Load Probabilities for Scenarios

	LOLP
Base Scenario	0.167%
Night 1.4kW	0.171%
Night 2kW	0.178%
Night 6kW	0.185%
Evening 1.4kW	0.189%
Evening 2kW	0.194%
Evening 6kW	0.217%

National Assessment

The above analysis was conducted for one subregion of the Southeast Electric Reliability Council. A broader study is being conducted on all 13 of the NERC regions in the U.S., as defined by EIA in their NEMS model (Fig. 13) for evaluation of electric demand and supply. Generation can be transmitted from one region to the other, based on the availability of both transmission links and available lower-cost generation. The Annual Energy Outlook 2007 (AEO2007) (EIA 2007) provided information on regional electricity sales and inter-regional trades, as well as other generation data, in order to establish regional supply and demand balances.

Hourly load data for 2005 from some 85 utilities or control areas was retrieved from the FERC website and aggregated into each of the 13 regions. Net inter-regional imports or exports were added to the demands and histograms calculated to create load duration curves for each region. Demands were escalated to 2020 values using AEO2007 projections. Generation supply for each region was also found from the AEO2007 results, being a combination of existing plants from their database of over 21,000 units and new plants built in response to expected demands between 2005 and 2020.

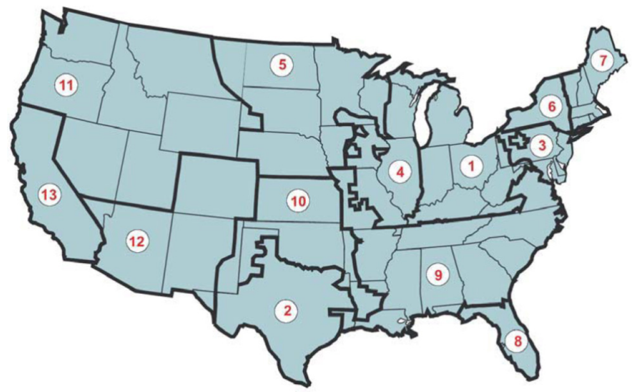

Fig. 13. NEMS Electricity Market Module regions (EIA 2007)

Vehicle sales for each region are projected by NEMS. As above, a market penetration curve for PHEVs was assumed and used to calculate the inventory of PHEVs for each region in 2020. It reflected a 25% market share of new vehicle sales by 2020. The number of vehicles in each region is shown in Table 6.

Table 6. Number of PHEVs in 2020 by region

Region #	Region	Millions of PHEVs
1	ECAR	2.44
2	ERCOT	1.41
3	MAAC	1.77
4	MAIN	1.84
5	MAPP	0.71
6	NPCC/NY	0.94
7	NPCC/NE	1.03
8	FRCC	1.20
9	SERC	3.38
10	SPP	0.44
11	WECC/NWP	1.04
12	WECC/RM-AZ-NM	0.69
13	WECC/CA	2.57

During the development of the national study, the ORCED model was enhanced to better capture small changes in the demand profile and seasonal differences. The LDC calculation was improved and the number of seasons was expanded from two (peak and offpeak) to three (summer, winter, and offpeak).

The dispatch decisions for each region are based on the variable costs, including SO_2 and NO_X emission credit prices from the AEO2007 for each region. They do not include renewable portfolio standards or other carbon-emission restrictions that might be in place by that time.

Regional Results

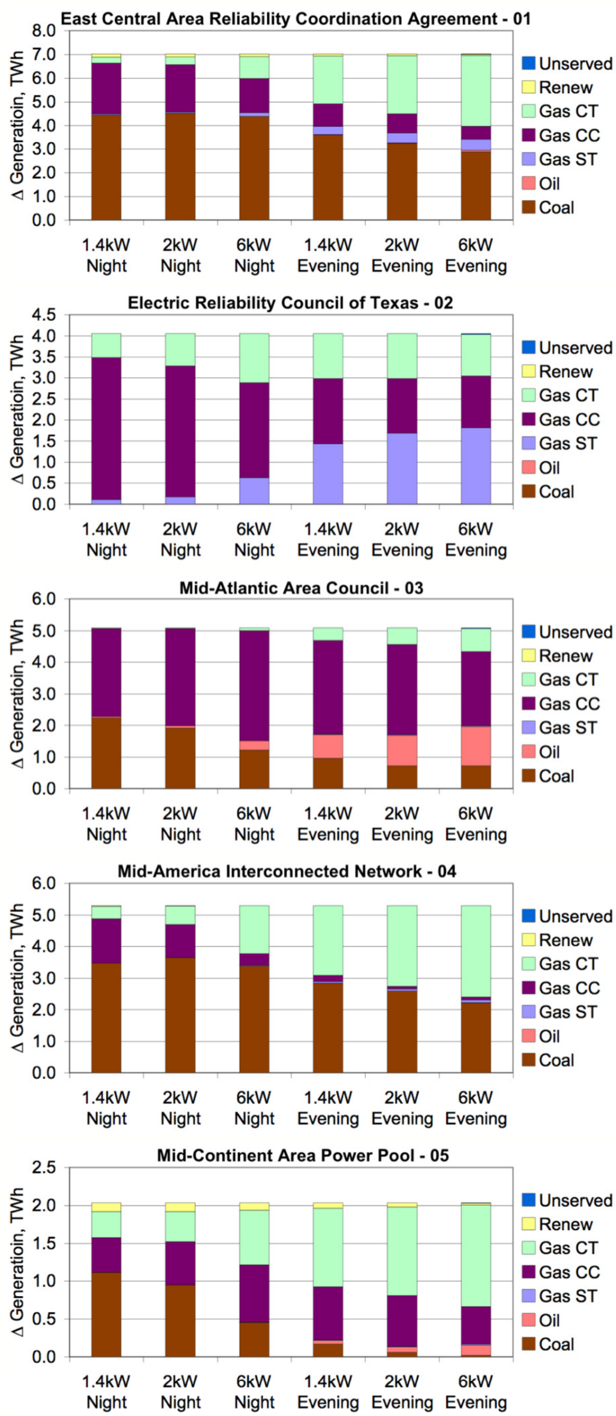

Fig. 14. Added generation by type with added PHEVs for Regions 1-5

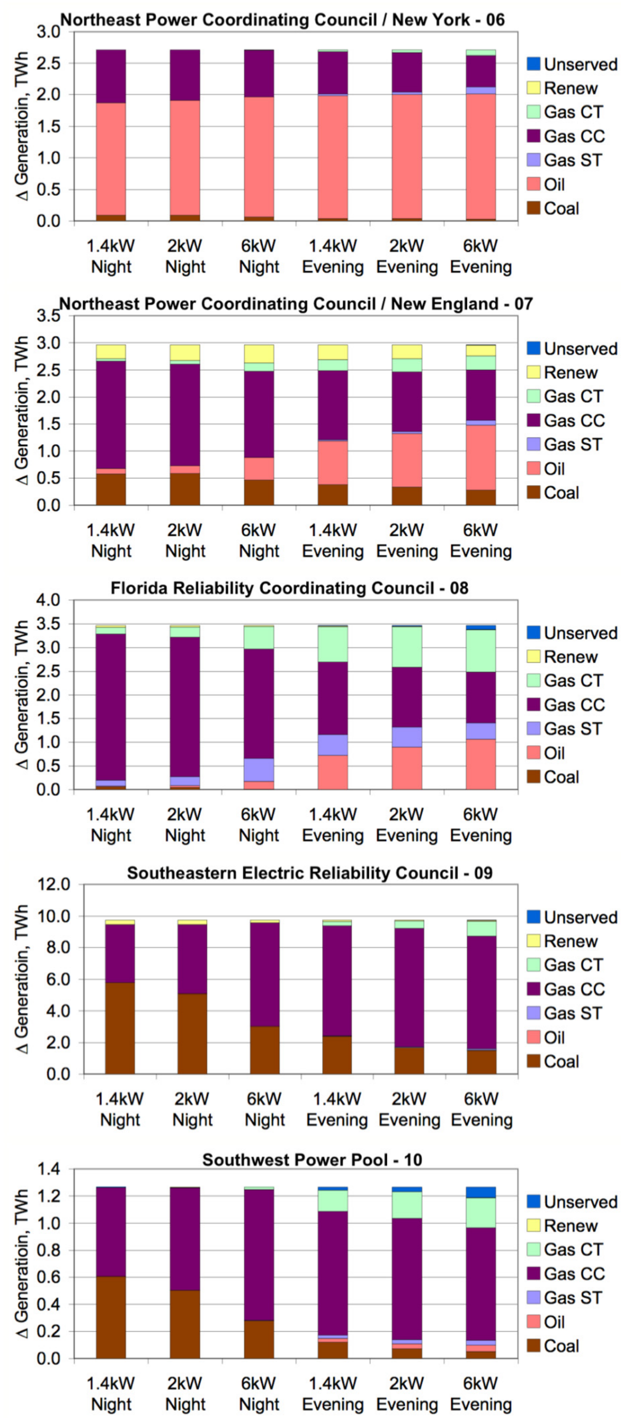

Fig. 15. Added generation by type with added PHEVs for Regions 6-10

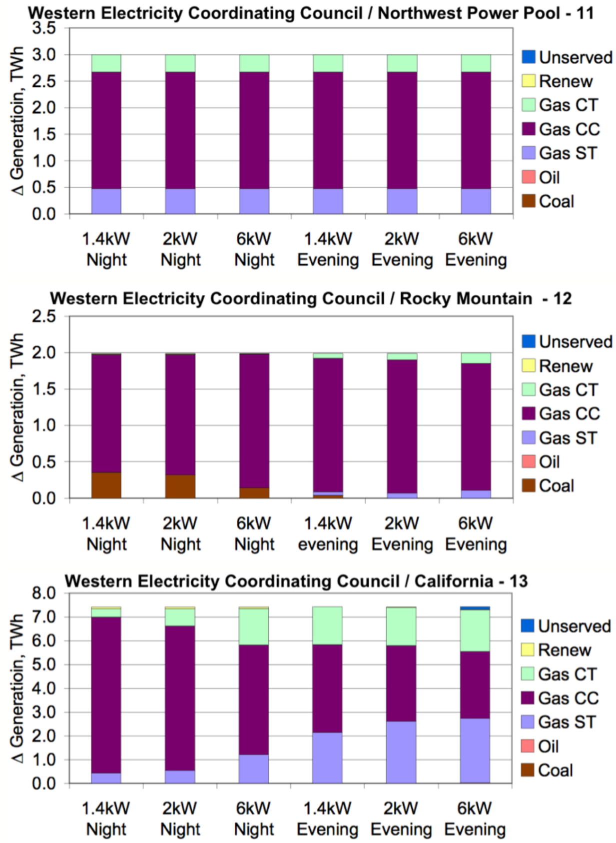

Fig. 16. Added generation by type with added PHEVs for Region 11-13

Figures 14 – 16 above show that most regions have gas-fired generation as the most frequent marginal producer, be it from combustion turbines (CT), combined cycle plants (CC), or steam turbines (ST). Nuclear, hydro, and wind generation do not appear in any of the charts because these technologies are never "on the margin". The nuclear plants are baseload and always operated to their maximum extent. If additional nuclear plants were to be built, the other plants with higher variable costs, including coal oil, and natural gas plants, would move higher in the dispatch order. Some may be retired. The mix of plants that are on the margin at different times would then change, but because of its low cost, nuclear would not likely become a load-following resource.

Hydro generation is energy-limited by the amount of water available. Changes in demand might change the timing of when the water is released and generation occurs, but the total amount will not change. Wind power is available when the wind blows. Its generation would not be affected by the change in demand; instead, other plants would be used to follow demand.

There are some interesting regional results. The NPCC/New York region shows a large component of oil-fired generation. This occurs despite oil representing less than 7% of generation in the region. There are a number of plants that can operate with either natural gas or residual fuel oil and ORCED modeled them as running on oil because of the lower cost of fuel.

Coal plays a role mainly in the Midwest and South, and generally during the nighttime charging periods, as was also displayed in the VACAR region described earlier. A few regions show renewables, mainly biomass, as a marginal fuel. New England has the largest amount, with power coming from wood-fired power plants.

A few regions showed some capacity issues (unserved energy) with the evening charging of PHEVs. These are areas which, based on the NEMS projections of capacity and demand along with the LDCs based on 2005 loads and assumptions on the timing of electricity trading, will have possible shortfalls in supply. In all likelihood, the utilities in the regions would expand their capacity, increase their imports, or establish demand response programs beyond what NEMS had calculated to avoid these problems, but these factors were not modeled in the scenarios.

Conclusions

This analysis identifies some of the complexities in analyzing the integrated system of PHEVs and the grid. Depending on the power level, timing, and duration of the PHEV connection to the grid, there could be a wide variety of impacts on grid constraints, capacity needs, fuel types used, and emissions generated. Some topics that could be more fully explored include:

- The relative emissions, gasoline use, electrical primary fuels use, and added generation needed to meet PHEV needs
- Consolidation of regional results to national totals
- Comparison of regional differences, including power supply capacity and cost, potential size of PHEV markets, and other electric market issues
- The impact of alternative vehicle operation schemes (longer distance batteries, partial charging, employer-provided daytime charging, vehicle to grid sales)
- Transmission and distribution impacts from PHEV
- Options for utilities to modify customer behavior
- Options for utilities and PHEV manufacturers to improve the vehicle/grid system
- Options for utilities to take advantage of PHEV characteristics to improve grid reliability

As we see by the above analysis, PHEV penetration of the vehicle market will create a substantial change on the electric grid. By evaluating these issues early, utilities, manufacturers, and regulators can better understand the issues involved and develop ideas that will better optimize the combined system.

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