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Emissions impacts of plug-in hybrid electric vehicle deployment on the U.S. western grid

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ABSTRACT

The constantly evolving western grid of the United States is characterized by complex generation dispatch based on economics, contractual agreements, and regulations. The future electrification of transportation via plug-in electric vehicles calls for an energy and emissions analysis of electric vehicle (EV) penetration scenarios based on realistic resource dispatch. A resource dispatch and emissions model for the western grid is developed and a baseline case is modeled. Results are compared with recorded data to validate the model and provide confidence in the analysis of EV-grid interaction outlooks. A modeled dispatch approach, based on a correlation between actual historical dispatch and system load data, is exercised to show the impacts (emission intensity, temporally resolved load demand) associated with EV penetration on the western grid. The plug-in hybrid electric vehicle (PHEV) and selected charging scenarios are the focus for the analysis. The results reveal that (1) a correlation between system load and resource group capacity factor can be utilized in dispatch modeling, (2) the hourly emissions intensity of the grid depends upon PHEV fleet charge scenario, (3) emissions can be reduced for some species depending on the PHEV fleet charge scenario, and (4) the hourly model resolution of changes in grid emissions intensity can be used to decide on preferred fleet-wide charge profiles.

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1. Introduction

A number of existing studies have found that plug-in hybrid electric vehicles (PHEVs) have emissions benefits over hybrid electric vehicles (HEV) and conventional vehicles even when accounting for grid emissions [1–4]. It has also been shown that the charge requirements of a conversion of a large portion of existing light duty auto fleets to PHEVs can be supported by existing grid infrastructure with minimal increases in annual energy demand [2,5–8].

One of the most important conclusions from prior studies is that emissions impacts of PHEVs are sensitive to the generation mix of a particular region [3,5]. While included as part of a previous study estimating percentages of light duty vehicle stock that could be supported by existing infrastructure in sub regions of the U.S. power grid [7], California has yet to be the subject of a comprehensive and detailed grid impact analysis covering emissions, operations, and the integration of a PHEV future. As a hub for innovation in transportation and energy, and having some of the most stringent environmental regulation programs in the nation, California serves as the world's laboratory in these areas and is well positioned for a detailed study. California is not an isolated system,

however, and depends heavily on imported power from neighboring states in the Pacific Northwest and Desert Southwest. California, with interchanges between these neighboring regions, makes up the western grid as defined in this study. Thus, while the focus of this study is impacts of PHEV deployment in California including the effects on California electricity system load, consideration of the broader western grid is required to capture the full impacts of such a deployment.

The focus of the current study is the description of a new methodology for modeling the resource dispatch and emissions of the western grid, and the application of the methodology to evaluate the impact of PHEV deployment for various charging scenarios and energy requirements. Prior grid scenario analyses and PHEV-grid interaction studies have used either grid models based on least cost unit commitment [2,3,9], the assumption that vehicle charging is provided by a single electricity generator technology [4], or an average regional or national grid mix [3,6,7,10,11]. The methodology presented herein is based on a correlation between system load and resource capacity factors identified in historical data that capture the complexity of resource dispatch without consideration of price signals, markets, and regulations that exist in the real system. The elimination of market influences in the dispatch consideration allows flexibility to vary many parameters for scenario analyses.

The basis for the structure and the model inputs are presented first, followed by a detailed description of the methodology itself. The methodology is then applied to a base case (actual system load

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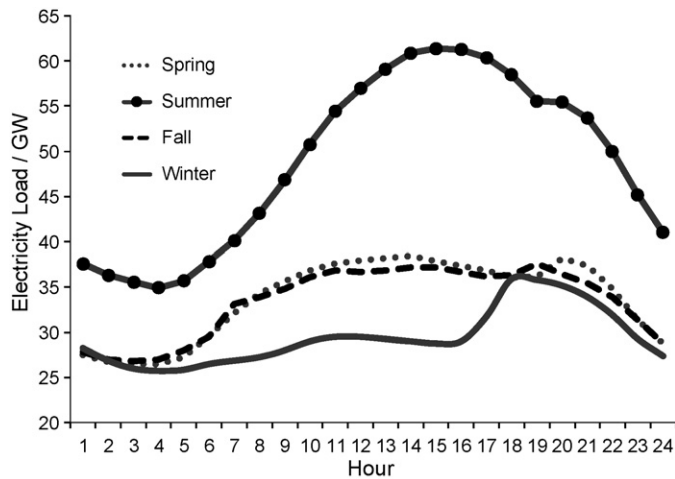


Fig. 1. Typical daily California system load profile by season.

during 2007), and comparisons are made to existing databases as a means of validating the methodology. Finally, the methodology is used to establish the impact of PHEVs on the hourly average grid emissions intensities of greenhouse gases (GHG), NO_x , CO, and NMTOC (non-methane total organic compounds).

2. California and the western grid

California's electric power system is comprised of roughly 1000 in-state generating facilities totaling 70,000 MW nameplate capacity and 40,000 miles of transmission lines [12]. Grid operations within California cannot be considered without recognizing the interties with neighboring states that, with California, form the western grid. Imports account for 20–30% (depending on the year) of annual electricity generation used to meet California electricity demand [13] and therefore make a significant contribution to grid emissions stemming from electricity generation to meet California demand. Production of in-state and imported electricity is responsible for 28% of California's GHG emissions second only to transportation at 39% [12]. The resource mix of the western grid is diverse, clean, and efficient compared to the rest of the nation [12], but growing population levels and temperature extremes coupled with ever increasing concerns for air quality require further improvements. To this end, California Assembly Bill 32 (AB32) requires reduction of statewide greenhouse gas emissions to 1990 levels by the year 2020. Additionally, the California Renewable Portfolio Standard (RPS) required by Senate Bills 1078 and 107 mandates that 20% of electricity be generated by renewable sources by 2010, reaching 33% by 2020.

2.1. System load profile and its variation

The shape of California system load varies daily but can be well characterized by looking at the typical profile for each season (Fig. 1). The shape of the system load is important because the system infrastructure must be built up to handle the peak loads that only occur roughly 100 h out of the year [14]. This results in underutilization of resources. Changing the shape of the system load to one that is more level throughout the day and over the year would have major positive impacts on grid operations such as improved generator reliability because of reduced transient operation, lower electricity cost due to more consistent generator up-time, and improved efficiency by operating generators near their design points. Thus, much can be learned by qualitatively looking at the shape of the system load curve for a given grid scenario.

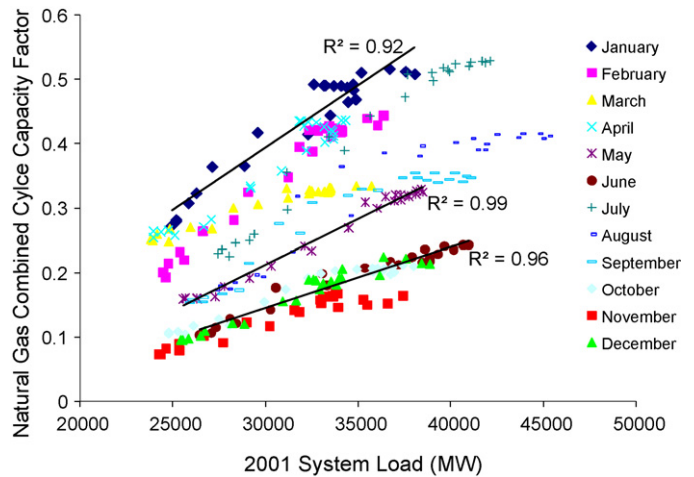


Fig. 2. Capacity factor versus system load correlation for combined cycle natural gas resources.

2.2. Resource capacity, emission factors, efficiencies, and dispatch order

Electricity generation resources are dispatched according to established rules based on resource technology duty cycles and contractual agreements between service providers and generation unit owners. For the western grid, this complex wholesale market is managed by the California Independent System Operator. Determining the dispatch of resources to meet system load at a given time is key in characterizing the operation of the grid. For the modeling performed in this work, a number of parameters are derived from the resource dispatch stack. Once power generation by each technology type is determined, emissions and water consumption can be found by using emissions and water consumption factors. Comparisons of emissions, load shape, and water consumption for different grid outlook scenarios can provide insight on the focus for future grid development.

3. Modeling methodology

3.1. Correlation based resource dispatch

Utilities commonly use sophisticated production cost models to simulate their systems [15]. The grid dispatch and emissions model developed herein does not explicitly call upon electricity production costs or a wholesale electricity market model to simulate resource dispatch. Instead, actual historical hourly dispatch data are used to predict future dispatch. The use of historical data captures the complexity in actual unit dispatch that stems from contractual agreements in the electricity market. The historical dispatch data are used to develop capacity factors as a function of total demand, and then these capacity factors define the amount of each resource that can be dispatched on a given hour.

Detailed disaggregated data made public by the Federal Energy Regulatory Commission (FERC) for the Western Markets Investigation (Docket No. PA2-02) contain output data for each generator in the California Independent System Operator (CAISO) control area for each hour of the year in 2001 [16]. Through extensive sorting and compiling of these data, it is possible to determine capacity factors for each generation technology on an hourly basis. With known capacity factor data and known system load data from 2001, a correlation can be established between capacity factor and system load for each technology type for each month of the year. As an example, Fig. 2 shows the correlation between average hourly capacity factor and average hourly system load for each month for natural

Table 1
Power plant technology groups and nameplate capacities.

| Generation technology | Installed capacity (MW) | Efficiency (%) | Notes |
|----------------------------------|-------------------------|----------------|---|
| In-State and Firm Import Nuclear | 5,568 | – | 80% In-State, 20% CA owned in AZ |
| In-State and Firm Import Coal | 4,052 | 34 | 14% In-State, 86% CA owned Out-of-State |
| Renewable | 7,623 | – | |
| Geothermal | 2,684 | | |
| Biomass | 1,073 | | |
| Wind | 2,202 | | |
| Solar | 380 | | |
| Small Hydroelectric | 1,284 | | |
| Natural Gas Cogeneration | 6,884 | 44 | |
| Hydroelectric | 12,042 | – | |
| Base load Gas Combined Cycle | 10,275 | 53 | |
| Non-Firm Imports | 13,100* | ** | *Limited by Transmission Capacity **Efficiency is based on efficiencies in import resource mix |
| Natural Gas Steam Turbine | 17,910 | 35 | |
| Natural Gas Peakers | 6,732 | 33 | 98% NGCT, 2% NGIC |

gas combined cycle facilities. Thus, for each technology group, 12 data series (one for each month) each consisting of 24 points (one for each hour of the average day) emerge. Trend lines are placed on a few of the data series in Fig. 2 to illustrate a statistically significant relationship between capacity factor and load (as shown by coefficients of determination, R^2 , greater than 0.9).

The correlations for the remaining technologies show similar levels of significance, with the exceptions of wind and solar resource groups for which insufficient data are available to provide a reliable correlation. For this work, solar generation was determined using a solar photovoltaic (PV) model that converts hourly insolation data into hourly PV system power output. Input data on hourly insolation is the most recent version of Typical Meteorological Year (“TMY3”) data, available from the National Renewable Energy Laboratory [17]. Variability in wind speed and resulting wind farm power output is modeled using a random number generator to produce random hourly wind speed profiles within bounds of the mean and standard deviation of hourly wind speeds obtained through actual weather station data. The result of this methodology is random, but statistically bounded, hourly wind turbine power output per 1.5 MW installed capacity. Additionally, because natural gas peaking units act to meet peak demand once other resources have been dispatched, it is assumed that these units have a potential to reach full nameplate capacity if needed and no correlation between capacity factor and load is used.

3.2. Resource dispatch algorithm

The dispatch and emissions model is developed in MATLAB and Microsoft Office Excel. Excel is used for storage of data fields used as input, as well as for storage and analysis of model output data. MATLAB is used for the heart of the model which is the resource dispatch algorithm. Dispatch of the thirteen resource technology groups, listed in Table 1, is modeled on an hourly basis. The capacity factor for each group for each hour is based on the derived correlations. These capacity factors define the amount of each resource that is available for a given hour. The dispatch of resources is then established using the algorithm shown in Fig. 3. For each hour, i , starting at hour 1, the system load, $L(i)$, is checked against the availability of Resource 1 during the given hour. If Resource 1 exceeds the system load, then the entire energy requirement of the system during hour 1 is met with Resource 1 and the model moves on to look at hour 2. Otherwise the next resource is dispatched either until it satisfies the remaining system demands or until it is dispatched to capacity. This process is repeated either until all resources are exhausted, in which case a “system overload” occurs, or until the

system load for the hour is satisfied with resources remaining and hour 2 can be modeled.

3.3. Resource capacities, efficiencies, and emission factors

Once the dispatch of resources is established, operating characteristics of each technology group are applied to arrive at modeled hourly emissions and fuel use. Electric power generation nameplate capacities for California by major technology type are reported in [13]. Each generation technology is assigned an aggregate fuel-to-electricity efficiency based on typical heat rates for each technology and the efficiencies reported in [18]. Table 1 summarizes the 2007 installed capacity and efficiency for each generation technology. While plant efficiency varies with rated power output, an average is used for simplicity. It is assumed that these operating points are typical and that generators operate near these efficiencies or else they are not turned on. For technology types that are comprised of more than one generator type or resource type, the efficiency is calculated using a weighted average of the constituent parts.

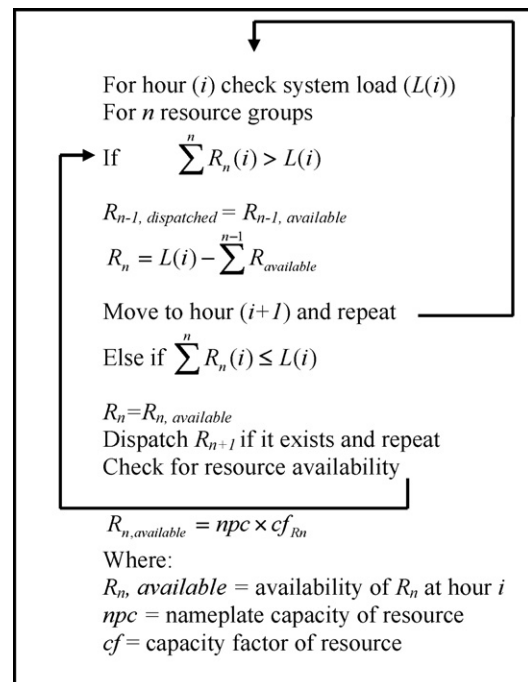


Fig. 3. Model dispatch algorithm.

Table 2
Generation technology type emission factors used in dispatch and emissions model.

| Resource group | Emission factors/g MJ ⁻¹ fuel burned | | | | | | | |
|------------------|---|-----------------|--------|--------|-----------------|-----------------|----------|------------------|
| | NO _x | SO _x | CO | PM | CO ₂ | CH ₄ | NMTOC | N ₂ O |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Coal | 0.1224 | 0.3473 | 0.0090 | 0.3311 | 87.3 | 0.00072 | 0.001080 | 0.001620 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.0946 | 0.0107 | 0.2580 | 0.1247 | 129.0 | 0.0090 | 0.0168 | 0.0056 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NG Cogeneration | 0.0239 | 0.0263 | 0.0331 | 0.0256 | 53.3 | 0.00094 | 0.002205 | 0.000971 |
| Hydroelectric | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Comb. Cycle | 0.0048 | 0.0003 | 0.0353 | 0.0042 | 50.7 | 0.00096 | 0.000903 | 0.000918 |
| Non-Firm Imports | 0.0444 | 0.1215 | 0.0144 | 0.1172 | 46.9 | 0.0006 | 0.0007 | 0.0009 |
| NGST | 0.0159 | 0.0003 | 0.0351 | 0.0008 | 50.7 | 0.00096 | 0.002296 | 0.000918 |
| NG Peaking | 0.0050 | 0.0003 | 0.0380 | 0.0050 | 50.7 | 0.00096 | 0.001901 | 0.000918 |

Emission factors for criteria pollutants and GHG's for each of the generation technologies are determined based on the emission factors in [19]. The primary information sources of these emission factors are EPA's AP-42 and eGRID power plant database [20,21]. Table 2 shows emission factors for each technology resource group. As with the efficiencies listed above, weighted averages are used to determine emission factors of resource groups that contain more than one generator technology.

4. Results and validation

4.1. Model results for the 2007 base case

Fig. 4 shows a result from the model for generator dispatch given the 2007 system load. This dispatch is based on the correlations between load and capacity factor for each resource group for each month of the year. The resource dispatch order shown in Fig. 4 is consistent with that observed in the actual operation of California's electric power system [22]. As expected, the base load technologies such as nuclear and coal are fairly constant throughout the year with the exception of months with capacity reductions due to the modeling of planned plant maintenance periods. Once the generation resource dispatch is determined for the year, many other grid operation characteristics can be derived, including: grid emissions and water consumption rates, fuel consumption, and operation of marginal generation technologies and how they compare to the average grid mix.

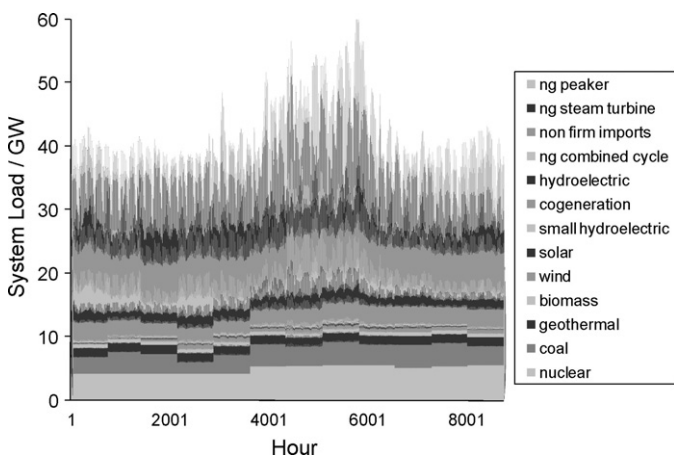


Fig. 4. Base case 2007 system load profile with modeled resource dispatch.

4.2. Model validation

4.2.1. Generation and resource shares results

The grid dispatch and emissions model uses nameplate capacities, knowledge of dispatch order, and hourly capacity factors to model the generation from each resource type to meet the California electricity load. The modeled and actual generation shares reported in [22] are compared directly by resource technology type in Fig. 5. The generation mix from the dispatch model is nearly identical to that reported in [22]. The largest portion of California generation (39%) is met by natural gas fired technologies, followed by 31% imports, 12% nuclear, roughly 8% hydroelectric, 9% total renewables, and less than 2% in-state coal. Natural gas plants, which include the NGST, NGCC, and NG Peaker technology categories, generate the largest fraction of total electricity by fuel type. Each individual resource group compares well with California Energy Commission (CEC) data on an annual GWh basis as well. The high level of agreement between the model and the CEC data in terms of relative contributions of resources and GWh of annual energy by resource suggests that the model dispatch well approximates the actual generation mix.

4.2.2. Emissions results

The eGRID 2007 database provides emissions characteristics of the grid in 2005 [21]. The eGRID database includes data for CO₂, CH₄, N₂O, NO_x, and SO_x, so comparisons between eGRID and the dispatch model are made for these species only. The dispatch model emission rate results are derived using the CEC emission factors for each technology type (which are originally calculated using eGRID and AP-42) and combining them with the results of the resource dispatch algorithm of the model. GHG data agree within 4% of eGRID estimates of average and marginal annual emissions rates for the region. The annual average NO_x emissions rates from this work are 19% and 27% lower than those given in eGRID. While assumptions from eGRID and the dispatch and emissions model are slightly different with respect to region and year of study, the comparisons validate the results of the dispatch and emissions model.

4.3. Impact of PHEV deployment on hourly emissions intensities of the western grid

4.3.1. Fleet aggregate charge profile descriptions

Marginal grid emissions from the charging of a fleet of electric vehicles are calculated in a unique way using the dispatch model. Typically, studies on grid connected vehicles base the vehicle related grid emissions on the emissions factors for the last technology to come on-line in the dispatch order, or on an average grid mix. This method is valid if the vehicle fleet energy requirement is very low and unexpected as would be the case for plugging

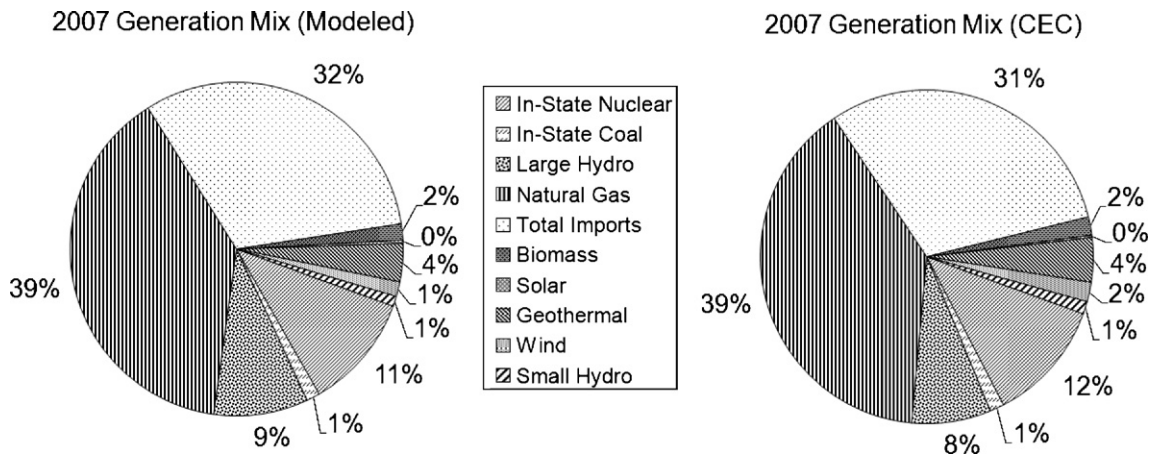


Fig. 5. Shares of annual energy production by generation technology type according to the model (left) and the CEC (right).

in only a single vehicle. However, in the case of large fleet penetrations, the new charge profile can be predicted and planned for on the electricity system operator’s day-ahead and hour-ahead schedules [6]. Therefore, the increased electricity demand over the baseline would be realized by increasing a number of resource technologies if sufficient capacity and economic justification are available. This is the method used for determining PHEV grid emissions with the model developed here.

Two fleet aggregate PHEV charge distribution profiles were developed for this work. Fig. 6 provides a graphic overview of each fleet aggregate daily charge profile for PHEVs. Each profile gives the percent of total fleet charging requirements that is needed by the fleet for a given hour. For each profile, the sum over all hours of the day will equal 100% of the charging requirement.

Best Guess At Likely. The “Best Guess At Likely” profile was developed as an approximation of what is likely given the assumption that charging time is at the discretion of the vehicle operator with no incentives or metering control to alter charge behavior. As shown, this scenario assumes readily available workplace charging for commuters during the daytime. This scenario results in mild peaks of charge frequency between 8 am–12 noon and again at roughly 5 pm through the evening. These peaks correspond to times when PHEV drivers will arrive to work and return home from work, respectively.

Ideal Valley Filling. The “Ideal Valley Filling” scenario is a theoretical scenario in which the charging of the fleet is carried out

in a way that levelizes the load curve as much as possible. This profile places more vehicle charging during hours of low system load, less vehicle charging during hours with greater existing load, and zero vehicle charge requirements during the hour of the existing peak. To achieve this charge profile for the fleet would require smart charging/metering infrastructure that is controlled or heavily incentivized by the utilities.

4.3.2. Impacts of PHEVs on the present day western grid

One of the key elements of the grid model presented herein is the ability to quickly change the load profile and to adjust resource dispatch based on the correlation between system load and technology capacity factor. This methodology finds a convenient application in the study of grid impacts of plug-in hybrid vehicles (PHEVs). The methodology used to evaluate the impacts of connecting PHEVs to the Western Grid involves determining the energy requirement of a PHEV fleet as well as the aggregate daily charge distribution profile. Once the fleet charging load profile is established, the additional load is added to the existing system load and the grid resource dispatch and emissions model is used to predict the resulting changes in grid operations and emissions.

For this study, 40% of the 2007 light duty auto (LDA as defined in EMFAC 2007) vehicle fleet is assumed to be range-extending PHEVs with an all-electric-range (AER) of 40 miles (PHEV 40). The 2001 National Household Travel Survey gives a measure of the cumulative percent of trips and cumulative percent of daily vehicle miles traveled (DVMT) for a given trip length [23]. These data show that 70% of drivers travel less than 40 miles per day. Therefore, a 40% penetration and 40 mile AER yields a 28% reduction in gasoline powered vehicle miles traveled each day. It is estimated that 451 million vehicle miles are traveled per day in California by the light duty auto fleet [24], leading to a total of 127 million all electric miles per day under the given scenario. It is assumed that the average PHEV requires 0.312 kWh/mi [4], leading to additional daily electricity demand in California of 45 GWh for the hypothetical 40% penetration of PHEV 40s (40PHEV40).

PHEV energy requirements and charge scenarios directly impact system load shape. The variation in system load shape then directly impacts resource dispatch, emissions, and utilization of resources. The altered load curves shown in Fig. 7 and the resulting changes in grid operations form the basis of the PHEV-grid scenarios solution capability.

This section provides a detailed comparison of the 2007 base case with the 40PHEV40 scenarios on an hourly average basis to explore hourly resolution grid impacts that are not captured by looking at annual averages. The 24 h period shown in each of the subsequent figures can be considered an average day for the whole

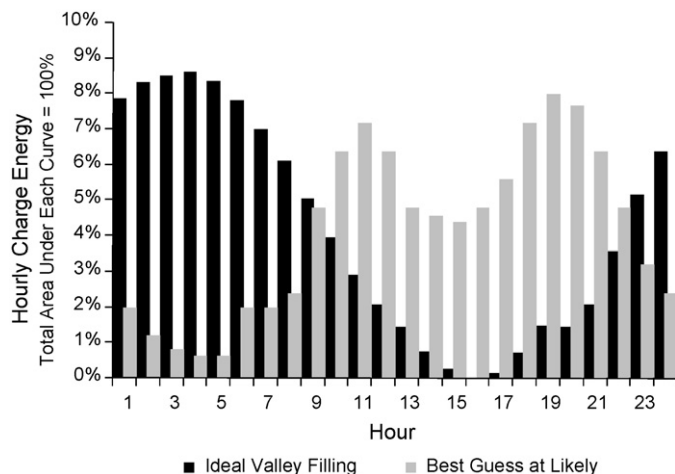


Fig. 6. Fleet aggregate daily charge distribution profiles for PHEVs.

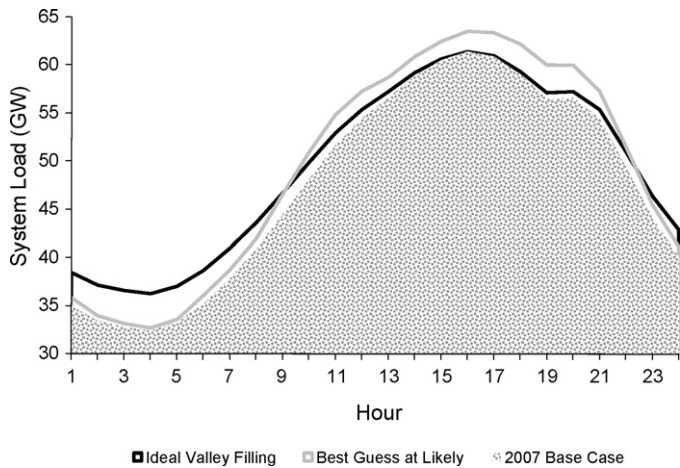


Fig. 7. Affect of PHEV charge time (profile) on system load.

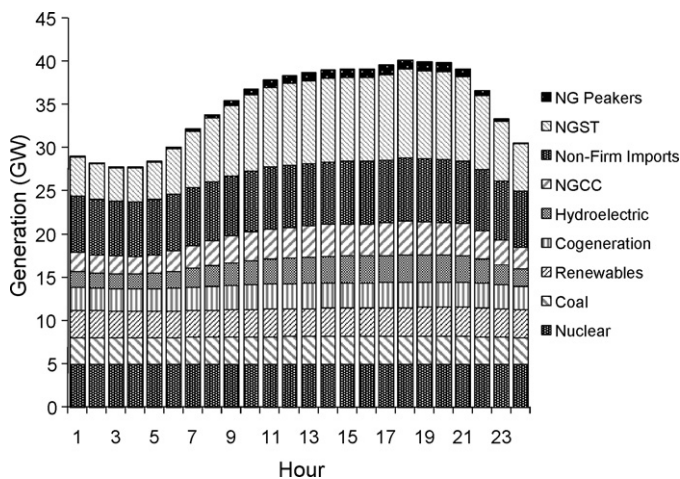


Fig. 8. Annual average generation mix by hour of day, 2007 base case.

year. For example, results given for “hour 1” are not representative of the hour 1 on any specific day, but rather show the average of hour 1 during each day in the year of study. Figs. 8–10 show the annual average system generation and generation mix on an hourly basis for the 2007 base case and the 40PHEV40 deployments with two unique charge profiles. The use of the “Ideal Valley Fill-

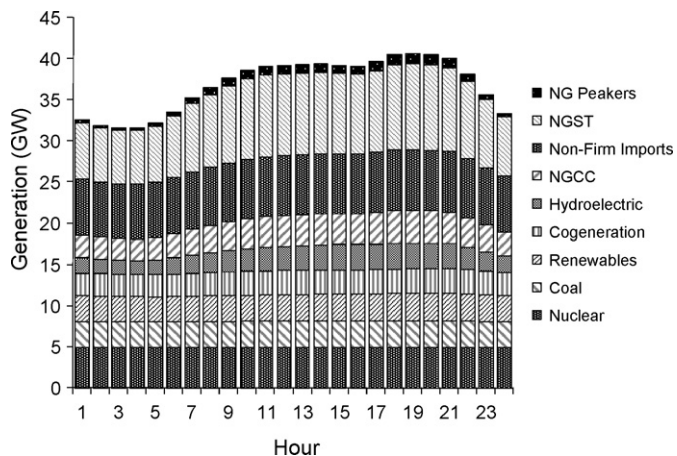


Fig. 9. Annual average generation mix by hour of day, 40PHEV40, “Ideal Valley Filling” scenario.

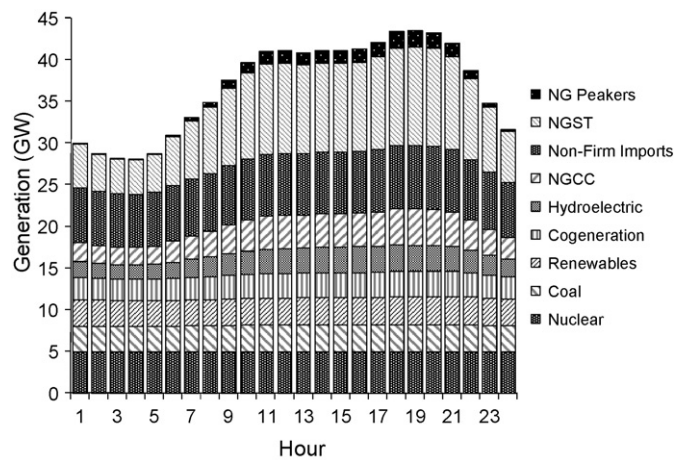


Fig. 10. Annual average generation mix by hour of day, 40PHEV40, “Best Guess At Likely” scenario.

ing” fleet charge distribution results in generation increases during the off peak hours, leading to a more level average load shape and therefore a more uniform grid mix across all hours of the day. The same deployment of PHEVs charged according to the “Best Guess At Likely” scenario results in roughly 5–10% higher electricity demand (compared to the base case) between the hours of 9 am and 9 pm corresponding to the charge distribution profile for this case.

Fig. 11 shows the hourly variation in GHG emission intensity for the 2007 base case and the 40PHEV40 deployments. The 40PHEV40 deployments both result in higher (or equal) GHG emissions intensity for both the average and marginal generation across all hours of the day. The difference between the two PHEV cases is in what hours of the day the emissions intensity increases occur. Marginal generation emissions intensity is roughly 40% higher than the average intensity for all hours. Since the GHG emission intensity of the marginal shares is greater than the average, the increase in generation due to the addition of PHEVs results in an increased average grid GHG emissions rate over the 2007 base case. Increased use of natural gas fired peaker units for marginal generation in the 40PHEV40 case leads to higher average marginal generation emission intensity during the off peak hours compared to the base case.

Fig. 12 shows the hourly variation in non-methane total organic compound (NMTOC) emission intensity for the 2007 base case and the 40PHEV40 deployments. Marginal NMTOC intensity decreases in the PHEV cases as natural gas peakers shares are increased because peakers have slightly lower NMTOC emissions than natu-

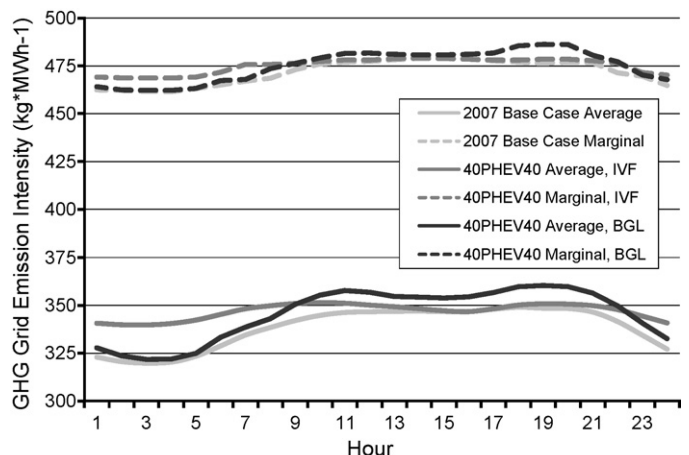


Fig. 11. Hourly grid average and marginal GHG emission intensity (kg MWh^{-1}).

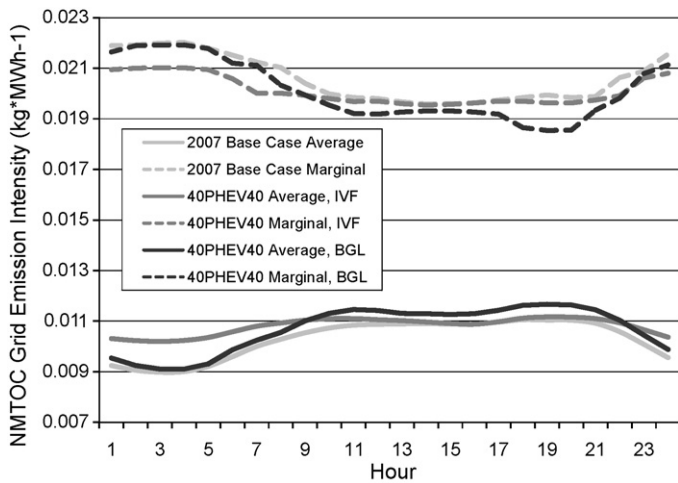


Fig. 12. Hourly grid average and marginal NMTOC emission intensity (kg MWh⁻¹).

ral gas steam turbines. Although the PHEV deployment can reduce marginal emissions intensity, average grid emissions intensity is increased by roughly 4% between hours 9 and 21 for the “Best Guess At Likely” scenario and 15% for hours 1–7 given the “Ideal Valley Filling” scenario. This increase comes as a result of increased use of natural gas technologies (which have NMTOC emission factors that are higher than the grid mix average) in the generation mix.

CO emissions intensity of marginal generation is much higher than that of the grid average for all hours of the day as shown in Fig. 13. Addition of 40PHEV40 to the base case scenario results in an increase in the grid average intensity. This increase is proportional to the generation increase. With the “Ideal Valley Filling” scenario placing most of the charge requirement in the off peak hours, the largest grid emissions increases, averaging 10%, occur during the off peak, between hours 1 and 11. The “Best Guess At Likely” charge scenario results in the greatest grid CO emissions rate between hours 9 and 21, although the change over the base case is only about 7% averaged over this time period. Marginal CO emissions intensity does not vary by hour even though the marginal generation shares do change hourly because the CO emissions of the marginal generation technologies are equivalent.

Addition of 40PHEV40 deployment to the base case results in a total reduction in annual average grid emission intensity of NO_x as well as a reduction across all hours of the day as shown in Fig. 14. Under the “Ideal Valley Filling” charge scenario the largest

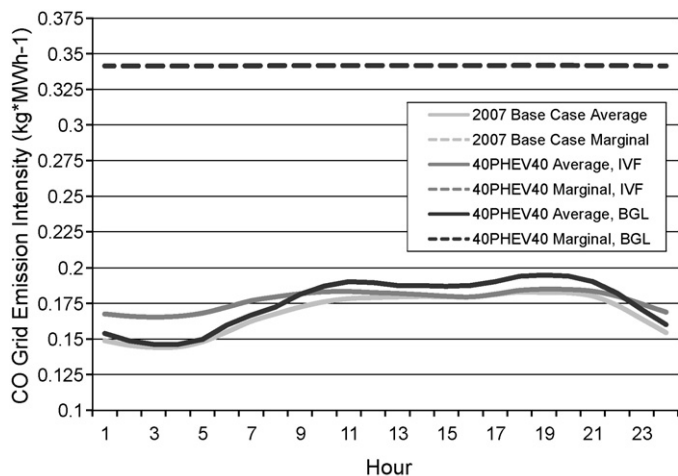


Fig. 13. Hourly grid average and marginal CO emission intensity (kg MWh⁻¹).

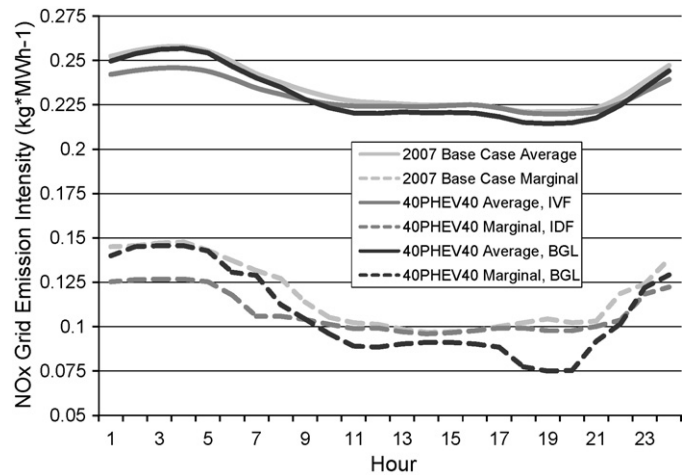


Fig. 14. Hourly grid average and marginal NO_x emission intensity (kg MWh⁻¹).

reductions in grid NO_x emission intensity occur during the early morning hours up to 11 am. These reductions average 3.5% for average grid emissions rates and 14% for marginal grid emissions rates. NO_x emissions intensity reductions for the “Best Guess At Likely” scenario occur during the second half of the day with the greatest benefit (30% reduction in marginal and 3% grid average) between hours 17 and 21. In both cases (base case and 40PHEV40), average NO_x emission intensity is greater than marginal by about a factor of 2. Marginal grid emission intensity is lower during the peak hours when the relative marginal share of natural gas peakers is higher. The increased use of natural gas technologies during peak hours to meet higher demand also results in lower grid average emission intensity during these hours.

5. Discussion

The grid research and emissions model has been developed and applied to the U.S. western grid using a historically based methodology to estimate resource dispatch on an hourly basis. The result is a robust capability in grid emissions modeling which can be used to explore electric vehicle impacts, scenario analysis, and load optimization. The approach described in this study yields hourly resolution grid emissions which are well suited for air quality modeling and determining impacts of load shape changes that will occur on an hour-to-hour basis such as PHEV charging, increased renewable integration, and demand response programs.

Hourly analysis of grid resource dispatch and emissions gives critical information for identifying preferred time-of-day EV charging profiles. The distinct differences in the two PHEV charge profiles analyzed in this study result in changes in grid emissions intensities at opposite segments of the day. For example, the “Ideal Valley Filling” charge scenario causes NO_x intensity to decrease and NMTOC intensity to increase in the morning hours whereas the “Best Guess At Likely” scenario has the same effects in the afternoon. Depending on the balance of these emission rate changes and the interaction with other influences in atmospheric chemistry which are not considered here, one PHEV charge scenario may prove preferable to the other. A definitive answer can be determined only from the use of a detailed air quality model. Expanding this approach to include a more refined, multi-node spatial element would further increase the value to air quality modeling of the grid. For example, the methodology can in principle be applied to a spatially resolved solution with multiple nodes by using the methodology at each node and connecting the nodes with a power flow algorithm layer to represent transmission of power from node to node.

Grid resource dispatch modeling using the correlation between system load and technology capacity factor in conjunction with a dispatch algorithm is an approach not previously used in modeling of an electric power system. This methodology is not based on resource prices or contracts but includes these elements inherent in the historical data used to derive the correlations. This method is believed to capture the intricacies of the real system without basing dispatch on price signals alone. The elimination of market influences in the dispatch consideration allows flexibility to change many parameters for scenario analyses. Hourly resolution provides insight in areas that may otherwise be overlooked. The resource dispatch, generation, and emissions results of the model for the 2007 base case compare well with existing reports by the California Energy Commission and by other research entities.

As noted previously, most PHEV analyses assume that all vehicle charging power is produced by peaker plants on the margin or that charging power is generated by an average grid mix. The total reliance on peaker plants is unlikely given the utility's ability to plan ahead, and the use of a grid average oversimplifies the grid dispatch and leads to power production increases in all technologies, including nuclear and renewables which might already operate at maximum capacity. The methodology developed and applied in this paper allows other, more realistic scenarios to be considered.

The conclusions of this study are:

- The correlation between system load and resource capacity factor can be used to model the change in resource mix with diurnal load variation.

The grid modeling methodology developed for this study identifies a strong correlation between total system load and capacity factor for each generation technology that provides a new way to model the resource dispatch under different scenarios. The methodology captures the complexity of actual operations because of the use of historical data in the correlations, but does not require the use of variable costs in the dispatch considerations. This approach lends itself to studies on grid emissions and load shape impacts where costs are not a main consideration. The hourly resolution for grid resource dispatch and emissions can lead to better understanding of air quality impacts of grid operations and electric vehicle charging by providing information on the variation in emissions with time. Validation of the model's ability to approximate resource dispatch and resulting emissions was made by comparison to data from the Energy Commission. These comparisons show excellent agreement of generation mix and marginal and average GHG emissions for the 2007 base case.

- Hourly resource dispatch and emissions modeling shows that the emissions intensity (lbs MWh^{-1}) of the western grid may increase or decrease (depending on the emissions species in question) with addition of PHEV charging demand.

The detailed grid dispatch methodology used here shows that a theoretical 40% PHEV penetration charged from the 2007 western grid will increase the western grid GHG, NMTOC, and CO emissions intensity (lbs MWh^{-1}) over the 2007 base case with no PHEV deployment. Only NO_x emissions intensity will be reduced with the addition of PHEVs because the increase in generation for vehicle charging comes from dispatched resources with lower NO_x emissions factors than the grid average NO_x emission factor in the case with no PHEVs. Additionally, these trends occur during both the "Best Guess At Likely" charge scenario and the "Ideal Valley Filling" charge scenario. These findings suggest that electric vehicle adoption should be accompanied by new, low-emission base load, generating capacity.

- The hourly resolution for modeling changes in grid emissions intensity as a result of PHEV charging under different scenarios can be used to select preferred fleet-wide charge profiles.

This decision can be based on the differences in air quality impacts that stem from the variation in hourly vehicle charge distributions and how these time-of-day impacts on grid emissions intensity interact with other factors such as sunlight and emissions from other sources.

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