G Model
POWER-12413; No. of Pages 11
ARTICLE IN PRESS

Journal of Power Sources xxx (2009) xxx–xxx

Contents lists available at ScienceDirect

Journal of Power Sources

journal homepage: www.elsevier.com/locate/jpowsour

Determining marginal electricity for near-term plug-in and fuel cell vehicle demands in California: Impacts on vehicle greenhouse gas emissions

Ryan McCarthy*, Christopher Yang

Institute of Transportation Studies, University of California, Davis, One Shields Avenue, Davis, CA 95616-8762, United States

ARTICLE INFO

Article history:
Received 20 August 2009
Received in revised form 12 October 2009
Accepted 12 October 2009
Available online xxx

Keywords:
Marginal electricity
Plug-in
Low carbon fuel
Climate change
Dispatch
Hydrogen

ABSTRACT

California has taken steps to reduce greenhouse gas emissions from the transportation sector. One example is the recent adoption of the Low Carbon Fuel Standard, which aims to reduce the carbon intensity of transportation fuels. To effectively implement this and similar policies, it is necessary to understand well-to-wheels emissions associated with distinct vehicle and fuel platforms, including those using electricity. This analysis uses an hourly electricity dispatch model to simulate and investigate operation of the current California grid and its response to added vehicle and fuel-related electricity demands in the near term. The model identifies the "marginal electricity mix" – the mix of power plants that is used to supply the incremental electricity demand from vehicles and fuels – and calculates greenhouse gas emissions from those plants. It also quantifies the contribution from electricity to well-to-wheels greenhouse gas emissions from battery-electric, plug-in hybrid, and fuel cell vehicles and explores sensitivities of electricity supply and emissions to hydro-power availability, timing of electricity demand (including vehicle recharging), and demand location within the state. The results suggest that the near-term marginal electricity mix for vehicles and fuels in California will come from natural gas-fired power plants, including a significant fraction (likely as much as 40%) from relatively inefficient steam- and combustion-turbine plants. The marginal electricity emissions rate will be higher than the average rate from all generation – likely to exceed 600 gCO_2 equiv. kWh^{-1} during most hours of the day and months of the year – and will likely be more than 60% higher than the value estimated in the Low Carbon Fuel Standard. But despite the relatively high fuel carbon intensity of marginal electricity in California, alternative vehicle and fuel platforms still reduce emissions compared to conventional gasoline vehicles and hybrids, through improved vehicle efficiency.

© 2009 Elsevier B.V. All rights reserved.

1. Introduction

Light-duty vehicles contribute significantly to greenhouse gas (GHG) emissions and petroleum consumption. In California, they account for two-thirds of transportation GHG emissions and approximately 20% of total instate emissions [1]. In an effort to mitigate these externalities, policies and research increasingly promote advanced vehicles that are more efficient than conventional vehicles or use alternative fuels. Among the most promising options are vehicles powered by biofuels, electricity, and hydrogen.

In California, energy policy is especially focused on reducing energy use and GHG emissions from transportation. Among others, the state recently adopted the Low Carbon Fuel Standard (LCFS), which directs refiners to reduce the carbon content of on-road transportation fuels [2]. To effectively implement the LCFS and other policies in an effective manner, it is critical for policy makers, regulators, and regulated entities to accurately calculate the lifecycle GHG emissions associated with various vehicle and fuel platforms.

Comparing energy use and emissions among distinct alternatives requires analysis on a "well-to-wheels" basis. Many previous studies have analyzed well-to-wheels emissions for a range of vehicles [3–9]. This type of analysis considers inputs and emissions upstream from the vehicle, from the "well-to-tank," as well as those that take place from the "tank-to-wheels." Emissions from conventional vehicles occur predominately from tank-to-wheels, during fuel combustion in the engine; only a small fraction of total emissions occurs during the extraction, refining, and transportation of petroleum to a vehicle's tank. In a plug-in hybrid electric vehicle (PHEV), well-to-tank emissions from electricity generation contribute significantly to overall emissions. In the case of a battery-electric vehicle (BEV) or hydrogen fuel cell vehicle (FCV), emissions occur entirely upstream from the vehicle's "tank," during the production of electricity or hydrogen and delivery to the vehicle.

Electricity is one of the most promising alternative transportation fuels and a key input for producing others, such as

* Corresponding author. Tel.: +1 530 754 4408; fax: +1 530 752 6572.
E-mail address: rwmccarthy@ucdavis.edu (R. McCarthy).

0378-7753/$ – see front matter © 2009 Elsevier B.V. All rights reserved.
doi:10.1016/j.jpowsour.2009.10.024

hydrogen, making electricity supply an important element of well-to-wheels analysis for many vehicle and fuel pathways. Characterizing upstream emissions requires detailed modeling of the electricity sector to correctly identify the "marginal mix" of power plants supplying vehicle and fuel-related electricity demands.[1] Ultimately, the marginal mix depends on the quantity, timing (the hourly distribution), and location of demand. These parameters determine the relative cost or benefit of using electricity as fuel, and must be accurately represented in modeling efforts.

This paper determines the marginal electricity mix and GHG emissions associated with operating advanced vehicles in California in the near term. An hourly electricity dispatch model with plant-level detail, the Electricity Dispatch model for Greenhouse gas Emissions in California (EDGE-CA), is described and applied to simulate grid response to added vehicle and fuel-related electricity demand in the state in 2010. Hourly electricity demand profiles for PHEVs, BEVs, and two hydrogen pathways fueling FCVs are developed and imposed on the electric grid. Specifically, this paper examines how different power plants are utilized and identifies the marginal generation mix likely to supply plug-in vehicle (BEVs and PHEVs) and hydrogen electricity demands, given the current composition of the grid in California. It explores marginal supply and emissions sensitivity to demand location and hydro-availability. Results from the electricity analysis are compared to estimated GHG emissions rates in the LCFS and extended to compare vehicle well-to-wheels GHG emissions based on likely near-term marginal generation mixes.

2. Background

2.1. Grid operation

The electricity grid is a collection of power plants and transmission and distribution facilities that produces and delivers electricity to customers in real-time. Because electricity cannot be practically stored in significant quantities, the grid has evolved to meet continually changing electricity demands by using a suite of power plants that fulfill various roles in the grid network.

Each type of power plant operates differently – using different size, technology, or energy resources to satisfy its function – and as a result, each has unique cost and emissions characteristics. Baseload facilities, often large coal or nuclear plants, are designed to operate continuously and at low cost. Peaking power plants, which are operated only a handful of hours per year when demand is highest, are often fired with natural gas, and are more costly to operate. Many other types of plants operate in between.

The mix of power plants that make up the grid will vary significantly from one region to another, based on local demand profiles, resource availability and cost, and energy policy. In any given hour, electricity demand is met with the lowest cost options first and increasingly more-expensive plants are dispatched until electricity demand is satisfied. Demand can also be met by imported power from other states or regions, if it provides a lower-cost generation than local generators can.

Electricity generation must match demand continuously, and adding electricity demand from vehicle recharging or hydrogen production and refueling will require additional power to be generated. The key to identifying the marginal mix of electricity for vehicles and fuels is to understand which power plants will generate this additional electricity.

2.2. Vehicle efficiency and fuel carbon intensity

Greenhouse gas emissions from vehicles ($gCO_2\,km^{-1}$) can be defined as the product of vehicle energy intensity[2] ($MJ\,km^{-1}$) and fuel carbon intensity ($gCO_2\,MJ^{-1}$). The use of advanced vehicle technologies and alternative fuels can reduce GHG emissions by improving vehicle efficiency (that is, reducing energy intensity) and lowering fuel carbon intensity [1].

Previous well-to-wheels studies have investigated a number of advanced vehicle platforms and concluded that they will likely have much lower energy intensities (they are much more efficient) than conventional internal combustion engine vehicles (ICEs) and conventional hybrid vehicles (HEVs). Battery-electric vehicles may be more than three times as efficient as an ICE, and more than twice as efficient as an HEV [3–6,10]. Efficiency of a PHEV depends on its operation. This analysis assumes that PHEVs operate as all-electric vehicles for some fraction of miles initially, then as HEVs until they are recharged. (Vehicles with 20- and 40-mile all-electric ranges are considered in this paper, and are referred to as PHEV20 or PHEV40, respectively.) Thus, at worst, PHEV efficiency is similar to that of an HEV, and at best – if operated entirely in all-electric mode – is closer to a BEV. Fuel cell vehicles are more than twice as efficient as ICEs and moderately more efficient than HEVs [3–6,10,11].

Carbon intensities of electricity and hydrogen can vary widely depending on production methods, highlighting the need to accurately determine marginal generation sources [12–14]. Although electricity and hydrogen can be produced from renewable sources – providing fuel with essentially zero carbon intensity – from the most common near-term methods, the carbon intensity of hydrogen and marginal electricity in California is *more* than that of gasoline. The well-to-tank carbon content of gasoline in California is equivalent to $96\,gCO_2\,MJ^{-1}$, or $346\,gCO_2\,kWh^{-1}$ [15].[3] But the carbon intensity of electricity from existing natural gas-fired power plants that are likely to provide marginal electricity in California is $450–700\,gCO_2\,kWh^{-1}$ [16]. And if hydrogen is produced onsite (at refueling stations) from natural gas steam-methane reformation (SMR), as expected during the first decades of a potential transition to FCVs, the carbon intensity of hydrogen fuel will likely be about $400\,gCO_2\,kWh^{-1}$ [12,17].

Nevertheless, relative vehicle efficiency improvements will generally outweigh the increase in fuel carbon intensity, and plug-in vehicles and FCVs will usually reduce GHG emissions compared to ICEs and HEVs. In order for all-electric driving to reduce emissions compared to an HEV, the ratio of plug-in vehicle energy intensity to that from an HEV must be less than the inverse of the respective ratio of fuel carbon intensities. This calculation is sensitive to comparative fuel economy assumptions of alternate vehicle platforms. It is possible, if marginal electricity is supplied by coal or another high-emitting power plant, and the efficiency improvement of a PHEV or BEV is relatively low, that all-electric driving could increase GHG emissions compared to an HEV. This is unlikely to occur in the near term in California, however, and PHEVs and BEVs should reduce emissions compared to HEVs [18].

[1] The marginal generator is the last power plant that is brought online (or dispatched) to supply demand in a given hour. The marginal mix, then, represents generation from the set of last power plants dispatched that is equal to vehicle demand. This definition assumes that vehicles require additional electricity and represent the last demand supplied in a given hour.

[2] Vehicle energy intensity is proportional to fuel consumption ($L\,(100\,km)^{-1}$) and inversely correlated with vehicle fuel economy (miles per gallon in the US).

[3] The energy content of a gallon of California reformulated gasoline is 115.63 MJ, or 32.1 kWh.

2.3. Marginal electricity and emissions

Attributing electrons from particular power plants to specific end use demands is a futile exercise. Nonetheless, it is assumed that in the near-term, vehicle and fuel electricity demands represent incremental demand above which the system was designed for. As a result, this analysis attributes generation from the last (marginal) generator brought online to these added demands. If incremental demand exceeds the excess capacity of the last generator operating, another plant is brought online and added to the marginal mix.

By this definition, which is used in other studies as well [7,19], marginal generators are the most expensive plants operating in a given hour, and likely, the least efficient. In this analysis, generation from hydro, nuclear, and renewable power plants, which have very low operating costs, is never on the margin. Instead, the marginal mix comprises generation from plants that would not be operating without added electricity demand from vehicle recharging or hydrogen production. In California, these plants are almost always natural gas-fired.

The marginal mix is distinct from the "average mix," which accounts for all electricity generation in a given hour. The two mixes may differ significantly, and consequently, so may their GHG emissions rates. In California, low-carbon resources such as hydro, nuclear, and renewable generation that are not part of the marginal mix are included in the average mix. Consequently, the average GHG emissions rate is lower than that of the collection of natural gas-fired plants that compose the marginal mix.

Over a longer term, as vehicle recharging and alternative fuel production become more predictable, their demand may be incorporated into utility planning. In that case, it may not be appropriate to simply attribute the generation from the last plants brought online to light-duty transportation. Such analysis and discussion is left for future work, however.

2.4. Vehicle demand impacts on electricity supply

Several studies have compared vehicle and fuel pathways on a GHG basis [3–9]. Typically, they apply a specific electricity mix, based on general assumptions about average electricity supply, to vehicle and fuel demands.

Other studies include vehicle demand impacts on electricity supply when estimating energy and environmental impacts of vehicles. But rarely do they compare across vehicle and fuel platforms.

Demand impact from BEVs on electricity supply was a popular research topic in the 1990s, in light of California's Zero Emission Vehicle (ZEV) Mandate. Ford considers the impact of adding 1–2 million BEVs in the Southern California Edison service area [20,21]. A contemporaneous report by the CEC investigates marginal generation and emissions of criteria pollutants associated with adding BEVs in the South Coast Air Basin [22].

Similar research is appearing for PHEVs. Many studies find that PHEVs could comprise a significant fraction of the light-duty fleet in California or the U.S. without requiring additional power plants or transmission capacity [23–27]. Some studies extend demand analysis to consider impacts on electricity supply or emissions. EPRI and NRDC present a thorough analysis of PHEV impacts on electricity supply in the U.S. [28,29]. Kintner-Meyer et al. consider PHEV electricity demand impacts on dispatch for a typical summer and winter day [24,30]. Parks et al. simulate costs, emissions, and resource use associated with PHEVs in the Xcel Service Territory [31]. Researchers at Argonne National Laboratory are investigating impacts of high penetrations of PHEVs on electricity generation in Illinois [32]. Samaras and Meisterling include lifecycle emissions in their accounting and consider various compositions of the electricity grid [33]. Hadley and Tsvetkova use the Oak Ridge Competitive Electricity Dispatch (ORCED) model to investigate impacts of PHEVs on electricity supply in 12 regions of the U.S. [19]. Other studies use accounting methods to estimate emissions and resource use associated with PHEVs operating in near-term and long-term electricity markets [25,34]. Some analyses have also investigated how plug-in vehicles could positively impact operation of the grid, by providing voltage regulation, load management, or spinning reserves [23,35–39].

While there is a large body of work regarding electricity as a fuel for electric-drive vehicles, no study was found that investigates GHG emissions impacts of multiple vehicle types in California in the near term using detailed electricity sector modeling. Near-term, California-specific analysis of electricity (per-kWh) and vehicle (per-km) GHG emissions is especially important in light of state policies – such as AB32, AB1493, and the LCFS – that require detailed accounting of vehicle and fuel emissions. This paper begins to address this gap.

3. EDGE-CA model methodology and description

3.1. Model overview

The EDGE-CA model is a spreadsheet-based simulation tool that models electricity generation and dispatch in California on an hourly basis over the course of a year to identify marginal power generation and GHG emissions supplying different vehicle and fuel-related electricity demand profiles. As stated above, a number of studies have developed electricity supply models to analyze the effects of plug-in vehicle recharging. The EDGE-CA model does not simulate grid dispatch in a particularly novel way, but uses a simple, merit-order approach to match supply with demand. These methods provide a transparent representation of electric generation in California that is appropriate for high-level analysis of demand impacts on supply and estimating resource use and GHG emissions. In actual power markets, sophisticated decision-making algorithms are used to dispatch generation optimally. Utilizing proprietary data and software, they simulate markets and constraints that are not included in EDGE-CA, including ancillary service markets, bilateral agreements and long-term contracts between generation companies and load serving entities, operational limits of power plants (such as minimum loading and ramp rates), reliability and distribution constraints, and emissions constraints of criteria pollutants. Without this complexity, EDGE-CA may misrepresent the exact mix of individual power plants operating at a given time. But given the large pool of power plants modeled (690 in-state plants), it does capture the *types of power plants* that operate throughout the state quite accurately, providing useful metrics for analysis of the current grid, and a useful framework for analyzing future grids, where specifying individual plants may not be necessary.

Sample outputs from an EDGE-CA simulation with added recharging demand from about 220,000 BEVs are illustrated in Fig. 1. Hourly generation by resource type and average and marginal electricity sector emissions rates are shown.

EDGE-CA is composed of three modules that determine electricity demand, power plant availability, and dispatch in three regions of California. The sections that follow discuss each in turn.

3.2. Regions

In EDGE-CA, California is divided into three regions and linked to two external regions from which it may import or export power (see Fig. 2). Northern California (CA-N) and southern California (CA-S) are separated, and linked, by the Path 26 transmission corridor. The boundary between the two is largely distinguished by the service territories of the two largest utilities in the state, Pacific Gas

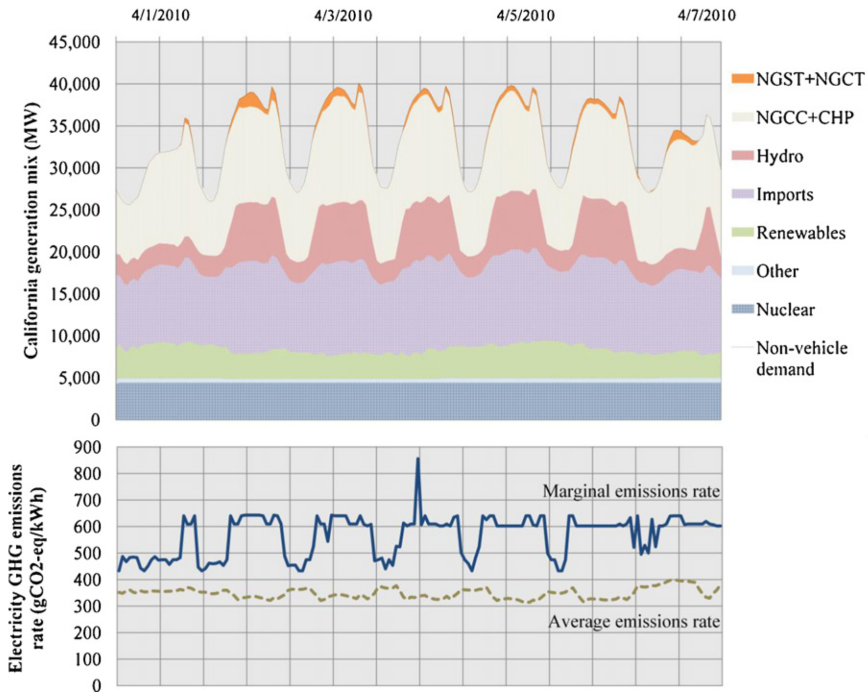


Fig. 1. Sample outputs from simulations with the EDGE-CA model, including GHG emissions rates from the average and marginal generation mix over the course of a spring week.

and Electric (PG&E) and Southern California Edison (SCE). A third region, territory served by the Los Angeles Department of Water and Power (LADWP), is distinguished from CA-S.

Exchanges among regions are limited by transmission constraints. Within California, transmission is limited to 3000 MW between CA-N and CA-S in and to 1000 MW between CA-S and LADWP [40,41]. Transfer capacity between California and other states in the Northwest is limited to 10,000 MW [42], and between California and other states in the Southwest, is 11,500 MW [43]. Transmission capacity between regions is held constant in the model. Direction of net flow, outages, temperature effects, and any other operational considerations that may affect line capacity are excluded from the analysis.

The mix of power plants that supplies electricity to each region is distinct. Northern California controls much of the state's hydro-resource and is directly connected to the hydro-rich Northwest. Southern California lacks significant hydro-power, and often relies on power from other regions during its peak demand. And LADWP accounts for most of the coal power consumed in California, in the form of "firm imports." (Firm imports represent generation from power plants located outside of California but controlled by instate entities, and are distinguished in EDGE-CA from "system imports," which comprise imported power purchased on the market, when economical.)

3.3. Electricity demand

The electricity demand module calculates vehicle demand and determines total hourly generation required to serve each region of California. Required electricity generation is equal to the sum of non-vehicle (conventional) demand, additional vehicle-related demand, and transmission and distribution losses. Non-vehicle demand follows hourly demand curves for each region in 2007 [46], scaled by estimated annual demand in 2010 [47]. Transmissions

	All CA	CA-N	CA-S	LADWP
Coal	15.7%	2.7%	9.8%	48.0%
Hydro	19.0%	22.2%	5.9%	6.0%
Natural Gas	41.5%	41.9%	53.3%	30.0%
Nuclear	12.9%	20.4%	16.6%	10.0%
Renewables	10.9%	12.9%	14.5%	6.0%

Fig. 2. Regions included in EDGE-CA and electricity consumption by energy resource in 2006 [44,45].

Table 1
Vehicle and hydrogen energy intensity assumptions.

	Vehicle efficiency parameters[a,b]			Vehicle energy intensity ($MJ\,km^{-1}$)[c,d]			H_2 energy intensity ($MJ\,kg^{-1}$)[e]	
	Relative fuel economy	Fuel economy ($km\,L^{-1}$)	All-electric fraction	Gasoline	Electricity	Hydrogen	Electricity	Natural gas
ICE	1.00	12.8	–	2.39	–	–	–	–
HEV	1.53	19.5	–	1.57	–	–	–	–
PHEV (ICE mode)	1.54	19.6	–	1.56	–	–	–	–
PHEV (electric mode)	3.00	38.3	100%	–	0.80	–	–	–
PHEV20	1.91	24.4	40%	0.93	0.32	–	–	–
PHEV40	2.18	27.8	60%	0.62	0.48	–	–	–
BEV	3.50	44.6	–	–	0.68	–	–	–
FCV (electrolysis)	2.32	29.6	–	–	–	1.03	195.5	–
FCV (onsite SMR)	2.32	29.6	–	–	–	1.03	10.5	179.4

BEV, battery-electric vehicle; FCV, fuel cell vehicle; HEV, hybrid electric vehicle; ICE, internal combustion engine; PHEV, plug-in hybrid electric vehicle; SMR, steam-methane reformation.

[a] Fuel economy based on scalars from [10] and assuming a fuel economy of 30 mile gal^{-1}, or 12.8 $km\,L^{-1}$, for new ICE vehicle.
[b] All-electric fraction of driving for PHEVs from [28], assuming 15,000 mile $vehicle^{-1}$ $year^{-1}$.
[c] Vehicle fuel economy is equal to the energy content of California reformulated gasoline divided by the sum of vehicle energy intensity by fuel type. The energy content of California reformulated gasoline is 115.6 MJ gal^{-1}, or 30.5 MJ L^{-1} [15] and 1 kg of hydrogen has the same energy content as a gallon of gasoline.
[d] 1 MJ = 0.278 kWh = 0.00865 gallon gasoline equivalent (CA reformulated).
[e] Hydrogen pathway electricity and natural gas intensity from DOE H2A analysis [48].

and distribution losses are assumed to be equal to 7% of generation in every hour.

Electricity demand impacts from seven vehicle and fuel pathway scenarios are considered. Conventional ICEs and HEVs are compared to PHEVs, BEVs, and FCVs. Fuel cell vehicle pathways include hydrogen produced at refueling stations from either electrolysis or SMR.

Assumptions regarding vehicle efficiencies and energy intensity of the pathways are listed in Table 1. Relative fuel economies are based on values from Argonne National Lab's GREET model and are not directly calculated within this analysis [10]. Actual fuel economies are scaled from the assumed value for a new conventional ICE vehicle (30 miles gal^{-1}, or 12.8 $km\,L^{-1}$). Well-to-wheels analysis is sensitive to the relative fuel economy of different vehicle platforms, and other values are certainly reasonable. But values from the GREET model provide transparent, well-documented, and widely utilized assumptions that are consistent with several other studies [3–9,11]. In addition to assumed fuel economy, the table lists vehicle energy intensity by fuel type and energy intensity associated with hydrogen production for the two pathways considered here [48].

Hourly electricity demand profiles for vehicle and fuel pathways are constructed by distributing annual energy demand daily, then hourly. Annual energy is determined from the parameters in Table 1 and assuming that 1% of light-duty vehicle-miles traveled (VMT) in California comes from one of the seven pathways. Light-duty VMT is expected to be about 329 billion miles in 2010 [47], which translates to about 220,000 advanced vehicles on the road. Annual electricity demand is distributed on a daily basis using gasoline sales data for California by week and day of the week [49,50].

Total daily electricity demand is distributed on an hourly basis according to three scenario timing profiles: *Offpeak*, *load-level*, and *gasoline* (see Fig. 3). The *Offpeak* profile applies to plug-in vehicles and matches the profile used in the EPRI and NRDC analysis [28]. It likely provides a reasonable representation of near-term aggregate recharging, with low demands during the day and most recharging occurring at night. The *load-level* profile distributes vehicle and fuel-related electricity demand to increase minimum daily electricity demand to the extent possible, thus partially filling overnight demand troughs (or "leveling" daily demand curves). It is applied to plug-in vehicles and the onsite electrolysis pathway and represents a best case scenario for near-term incremental demand, from a grid operation perspective. Finally, the *gasoline* profile assumes electricity use follows the pattern of hourly gasoline refueling [49]. It is used to simulate hydrogen production and refueling at small scales and with little storage, where hydrogen is essentially produced as it is needed for refueling at a hydrogen station.

As illustrated in Fig. 3, electricity demand from these vehicles would have a minor impact on overall demand. If 1% of VMT were to come from FCVs using grid electrolysis – and unlikely near-term scenario – total electricity demand increases by 0.7% and peak

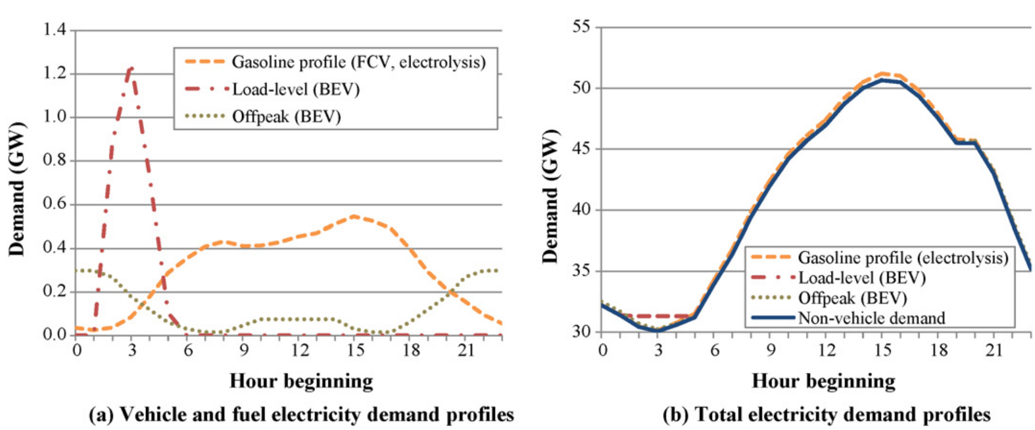


Fig. 3. (a) Sample vehicle and fuel electricity demand profiles and (b) impacts on total demand, for a representative June day.

Table 2
Summary of California electricity generation resources in 2010, as represented in EDGE-CA.

	Capacity (MW)	Availability and notes
Baseload/renewable		
Nuclear	4,577	Hourly availability constant in a month; monthly energy based on historical distribution [16,51,57–59]
Geothermal	2,265	
Biomass	1,571	
Solar	739	Follows 1998 insolation profile for Palm Springs, California [60]
Wind[a]	3,083	Wind speed profile for four regions in California [61]; generation based on power curve for Vestas V47 turbine [62]
Firm imports	6,193	California ownership of out-of-state plants from [63,64]
Nuclear	1,153	Nuclear from historical distribution of generation in Arizona [59,65]
Coal	3,896	Coal generation constant in all hours of year
Function of demand		
Hydro	1,143	Firm import hydro-availability follows California hydro-profile
NW imports[b]	8,000	Mix: 9% coal, 2% nuclear, 66% hydro, 22% natural gas, 1% renewable [43]; Regional fractions of NW imports from [46,54]; NW imports = −5344.6 + 7827.4**nload* + 0.040**peak* − 0.347**cahydnuk* − 3.267**wahdd* + 0.535**wahyd* (adj. R^2 = 0.72)
SW imports[b]	7,000	Mix: 4% coal, 96% natural gas [43]; SW imports = −1997.7 + 4152.9**nload* + 0.111**peak* − 0.468**cahydnuk* − 1.941**nwreg* + 0.335**azdd* − 0.345**aznuk* (adj. R^2 = 0.56)
Hydro	7,000[c]	Annual available energy from historical distribution [57,58]; About 16% of hydro is baseloaded (run-of-river); The rest is: load-following above a threshold (October–February), or $^2/_3$ of monthly energy dispatched at peak capacity (7000 MW) in as few hours as possible (March–September)
Dispatchable		
Coal	363	Dispatched plant-by-plant as needed, in order of increasing variable cost;
Oil	568	Availability limited by scheduled and forced power plant outages [55,56];
Other	49	Variable costs = Variable O&M + Fuel costs;
CHP	2,962	Variable O&M costs from [66];
NGCC	19,207	Fuel costs from plant heat rates from [16] and assumed energy costs: \$6 MMBtu^{-1}
NGST	7,796	(oil), \$7 MMBtu^{-1} (natural gas, CA-N), \$6.5 MMBtu^{-1} (natural gas, CA-S and
NGCT	10,099	LADWP), \$1.50 MMBtu^{-1} (coal), \$2.50 MMBtu^{-1} (biomass)

CA-N, Northern California; CA-S, Southern California; CHP, combined heat and power; LADWP, Los Angeles Department of Water and Power; NGCC, natural gas combined cycle; NGCT, natural gas combustion turbine; NGST, natural gas steam turbine.

[a] Wind capacity includes capacity as of December 31, 2008 [67] and projected additions in 2009 and 2010 [68].

[b] Regression parameter Refs. [41,59,69] *nload* = hourly California load, normalized to monthly peak demand; *peak* = monthly peak demand; *cahydnuk* = monthly hydro + nuclear generation in California; *wahdd* = monthly heating degree days in Washington state; *wahyd* = monthly hydro-generation in Washington state; *nwreg* = hourly net imports from the NW import regression; *azdd* = monthly degree days in Arizona; *aznuk* = monthly nuclear generation in Arizona.

[c] Installed hydro-capacity in California is 13,162 MW, but the effective peak capacity is usually about 7000 MW, which is the peak allowed in EDGE-CA. During some "super-peak" hours, hydro-generation may be about 11,000 MW [70], but super-peak events are not included in EDGE-CA.

demand increases by 1%, on this day. Demand impacts from the other profiles shown are much smaller, and smaller still for the vehicle and fuel pathways not shown (PHEVs, and onsite SMR).

Vehicle electricity demand is distributed among the three regions based on the regional fractions of annual statewide demand. The impact of shifting vehicle location on GHG emissions is investigated in sensitivity analyses.

3.4. Power plant representation

Power plants are represented in EDGE-CA primarily based on data from the U.S. EPA's eGRID database [16]. The database provides plant-level data for U.S. power plants operating in 2005. Importantly, it includes plant capacity, total annual generation, heat rate (the inverse of plant efficiency), and GHG emissions rates (CO_2, N_2O, CH_4) data for 690 power plants in California and 1195 power plants collectively in the CA/MX, NWPP, and AZNM supply regions as defined by the North American Electric Reliability Corporation (NERC). Data from eGRID is supplemented with information from NERC's Electricity Supply and Demand (ES&D) database [51] and the U.S. EPA's National Electric Energy Data System (NEEDS) [52] to help categorize power plant type, location, and ownership.

The simulations presented here use the grid as it existed in 2005 with added renewable capacity that is expected online before 2010 to help meet California's Renewable Portfolio Standard [53]. Although natural gas-fired capacity has been and will be subsequently added, as well, it is assumed that the dispatchable fossil plant mix developed here is representative of that which will exist in 2010.

These detailed power plant data are used to construct supply curves that describe the quantity of electricity available at a given price for each region in each hour. The regional supply curves are compared and power is traded among regions to minimize the variable cost of the last plant brought online statewide, subject to the inter-regional transmission constraints.

Available generation from power plants is determined in one of three ways (see Table 2). First, renewable and baseload generators, including most firm imports, follow fixed hourly generation profiles that are independent of electricity demand. They do not provide marginal generation for vehicle and fuel-related electricity demand in any scenario in this analysis.

Second, hourly supply from system imports and hydro-facilities are determined as a function of the hourly demand profile. Hydro is an energy-constrained resource, as only a fixed amount of water is available annually. A typical capacity factor for hydro-generation in California is about 30% [16], but it varies depending on annual precipitation. In EDGE-CA, available hydro-energy is constrained on an annual and monthly basis. Monthly generation is dispatched on a daily and hourly basis according to a set of simplified rules that attempts to minimize generation from dispatchable natural gas-fired power plants. Hydro-dispatch indirectly affects the marginal mix of generation for vehicles and fuels, but it does not provide marginal energy.

Hourly generation from system imports are also simulated in this analysis, through regression models developed from historical hourly imports data [54] from 2005 to 2007. The models are listed in Table 2 and fit the data quite well, resulting in adjusted R^2 values of 0.72 and 0.56 for NW imports and SW imports, respectively. Northwest imports uses conditions in Washington as proxy for the region, and is a function of hydro-generation in Washington and California, nuclear generation in California, hourly demand in California, and monthly heating degree days in Washington.[4] Southwest imports uses conditions in Arizona as proxy for the region, and is a function of demand in California, hydro-generation in California, nuclear generation in California and Arizona, NW imports as defined from the regression, and overall degree days (heating plus cooling) in Arizona.

Third, dispatchable, fossil power plants in California are queued in order of increasing variable cost and dispatched until total demand is met. The availability of dispatchable generators is limited by scheduled and forced outages, which is determined randomly based on outage rates by plant type and month [55,56].

The GHG emissions rates presented in the results are in terms of *kWh of demand* and are scaled to account for transmission losses and emissions that occur upstream from the power plant. Upstream emissions are assumed to be 12.6 gCO_2 equiv. MJ^{-1}, or 45.4 gCO_2 equiv. kWh^{-1} for natural gas-fired generation [71]. They are added to the marginal emissions rate, which is subsequently scaled by a factor of 1.07 to account for emissions in terms of demand, rather than generation.

3.5. Model validation

The EDGE-CA model was run to backcast supply, and the results were compared to historical data from 2005 to 2007 to validate the model. The simplifying, aggregate methods underlying EDGE-CA and the disparate data sources used lead to some deviation in generation by resource in some years. But on average, generation by resource type matches the data well [57,58]. Modeled natural gas generation varies from historical data by ±5% in some years, but is within half of one percent of the observed value when averaged over the three years. Estimates of firm imports in EDGE-CA derive from different data [63,64] than is used by the California Energy Commission (CEC) [43,72], and the model results underestimate coal-fired generation by an average of 1.2 TWh compared to CEC data (about 0.4% of average annual generation).

Results from EDGE-CA likely underestimate average GHG emissions rates in California. While there are noticeable differences and discrepancies in the reported data themselves, estimated GHG emission rates in EDGE-CA are uniformly lower. In 2005, for example, EDGE-CA predicts an average annual GHG emissions rate from instate generators of 250 gCO_2 equiv. kWh^{-1}, compared to estimates from the U.S. Energy Information Administration (294 gCO_2 kWh^{-1}) [65,73] and the U.S. EPA (263 gCO_2 kWh^{-1}) [74]. Estimates from the California Air Resources Board (ARB) that include imports are about 9% higher than similar estimates from EDGE-CA [71].

The discrepancy among the values mostly results from differences in the average efficiency of natural gas-fired generation. Generation fractions by power plant type and average heat rates

[4] Degree days reflect heating or cooling energy demands. They are defined as the difference between the average daily temperature and 65 °F (18 °C).

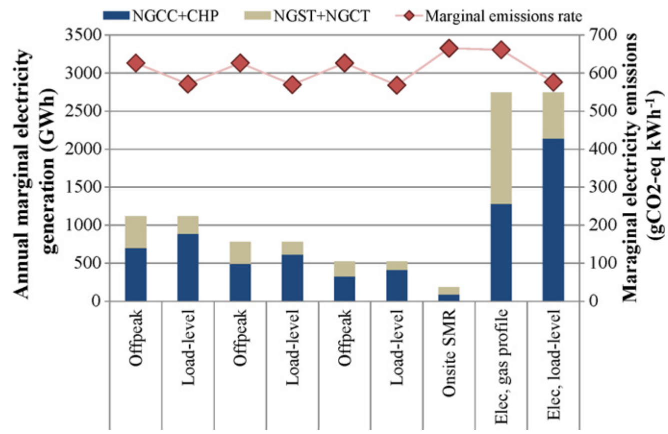


Fig. 4. Marginal electricity generation and direct GHG emissions rates by vehicle and fuel pathway.

vary noticeably by reporting agency. Compared to ARB, EPA, and EIA data, EDGE-CA overestimates generation from relatively efficient natural gas combined cycle (NGCC) and plants and from plants operating in CA-N, while underestimating generation from less efficient natural gas steam turbine (NGST) and natural gas combustion-turbine (NGCT) plants, which are predominately located in CA-S. The large distinction from the EIA data stems from an especially high heat rate that it reports for NGCT plants [59].

To the extent that EDGE-CA underestimates average GHG emissions rates, it likely underestimates marginal emissions rates, as well.

4. Results

The EDGE-CA model simulates California electricity supply in 2010 for systems that include additional demand from the vehicle and fuel scenarios. Results from these simulations – pertaining to the marginal electricity mix and GHG emissions rate – are discussed in the next two subsections. The third subsection extends the analysis to determine well-to-wheels vehicle emissions, and the final subsection discusses implications for energy policy in California.

4.1. Marginal electricity supply in 2010

The marginal generation mix for each pathway is illustrated in Fig. 4. The results represent base case assumptions regarding median hydro-availability (about 35,000 GWh annually) and geographical distribution of marginal demand (in proportion to non-vehicle electricity demand: 42% in CA-N, 49% in CA-S, and 9% in LADWP). Generation from NGCC and natural gas combined heat and power (CHP) plants are combined in the figure because both tend to operate with relatively high capacity factors and similar GHG emissions rates. Generation from NGST and NGCT plants is also combined, as both plant types have GHG emissions rates that are about 50% higher than NGCC or CHP plants. A small amount of marginal generation comes from other plant types (much less than 1%), but is not shown for clarity. The associated GHG emissions rate from marginal generation is given as well, on the right axis.

The fraction of generation from NGST and NGCT plants and the marginal electricity GHG emissions rate decreases as demand shifts to off-peak hours. For the *load-level* profile, where all demand occurs off-peak, about 21% of marginal generation comes from NGST or NGCT plants and marginal electricity GHG emissions

Please cite this article in press as: R. McCarthy, C. Yang, J. Power Sources (2009), doi:10.1016/j.jpowsour.2009.10.024

rates are about 570 gCO_2 equiv. kWh^{-1}. The *Offpeak* profile spreads recharging demand throughout the day, though still predominantly at night. In scenarios with that recharging profile, 37% of generation comes from NGST or NGCT plants and marginal emissions are about 625 gCO_2 equiv. kWh^{-1}. The majority of demand occurs during the day in the *gasoline* profile, and NGST and NGCT plants supply more than 50% of marginal demand for hydrogen supply. As a result, marginal GHG emissions rates are relatively high, about 660 gCO_2 equiv. kWh^{-1}.

Based upon these assumptions, the carbon intensity of marginal electricity is 65–90% higher than that of gasoline. If this marginal electricity were used as fuel, electric-drive vehicles would need to be that much more efficient than a comparable gasoline vehicle to offer GHG emissions reductions in California.

Generally, as the quantity of electricity demand for a given recharging profile increases, so does the fraction of marginal generation from NGST and NGCT plants and the marginal electricity GHG emissions rate. Thus, one would expect marginal emissions rates to be higher for BEV pathways than for PHEV pathways using the same charging profile.

But they are very similar in these results, due to the relatively small amount of electricity demand required to supply 1% of light-duty VMT. During many hours, increased demand for BEV recharging is insufficient to require the dispatch of additional power plants to the marginal mix, compared to PHEV scenarios, and the same marginal generator operates in either case. Even when the demand difference is more noticeable, during off-peak hours, the subsequent generators added to the marginal mix often have similar characteristics to those operating before them. California has a large stock of CHP and new NGCC plants that operate with similar emissions rates and are available on the margin when dispatch requirements are low.

4.2. Sensitivity analysis of marginal generation

The previous results represent marginal supply under typical conditions, averaged over the course of a year. But electricity supply is highly dynamic and actual emissions may vary significantly from average, depending on when and where hydrogen is produced or a vehicle is recharged. This section explores the sensitivity of the marginal mix and GHG emissions rates to hydro-availability, demand location, and demand timing.

Annual generation in California is very sensitive to changes in hydro-availability resulting from varying precipitation patterns and quantity. In a given year, instate hydro-generation may range from 20,000 GWh to 60,000 GWh and may account for anywhere from 10 to 20% of statewide electricity consumption [57]. In dry years (or months), additional natural gas-fired generation (from instate or out of state) mostly replaces lost hydro-energy [18], and marginal generation is likely to come from less efficient natural gas power plants than it does otherwise. The opposite holds in wet months and years.

The regional representation of supply in EDGE-CA creates a sensitivity to demand location. Relative demand among the three regions affects generation transfers, and transmission constraints and regional supply differences affect which power plants operate on the margin. In EDGE-CA simulations, shifting demand to the LADWP region typically reduces marginal emissions rates compared to the baseline, because the region often has excess NGCC capacity available for export when its dispatch requirements are low. Adding demand in CA-S typically increases marginal emissions rates, because NGCT plants often operate on the margin there.

The sensitivity of marginal supply and emissions to hydro-availability, demand location, and season is explored in Fig. 5. The figure illustrates results for presumed high, average, and low emissions conditions for the three timing profiles.[5] The high case represents marginal generation during a 1-in-10 dry year (24,235 GWh of annual hydro-generation) with all marginal demand in CA-S. The low case depicts a 1-in-10 wet year (50,879 GWh $year^{-1}$), if all marginal demand were in LADWP. The base case shows the annual average using the baseline assumptions described in the previous section.

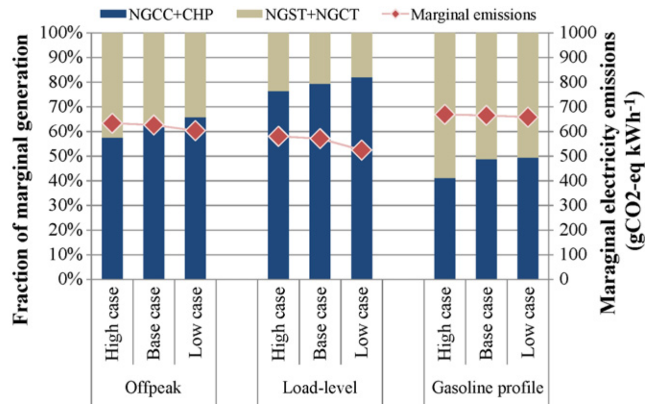


Fig. 5. Sensitivity of marginal generation and GHG emissions rates to hydro-availability, demand location, and season.

Marginal generation and emissions rates are relatively insensitive to the three parameters, but there is some variation. The marginal mix varies most in the *Offpeak* profile, where the share of NGCC and CHP generation is about 8% lower in the high case and 4% higher in the low case, compared to baseline assumptions. Marginal emissions rates vary most noticeably using the *load-level* profile, where emissions in low case are almost 50 gCO_2 equiv. kWh^{-1} lower than in the base case.

Interestingly, the marginal mix of generators is more sensitive to assumptions in the high emissions case than in the low emissions case, but the opposite holds for marginal emissions rates. This suggests some variation in the efficiency and emissions rates of marginal generators operating within a category. For example, NGCC plants may provide marginal generation for a given pathway in a given hour, regardless of sensitivity assumptions. But more efficient NGCC plants may be operating on the margin in a wet year than on average.

There is more variation in marginal emissions rates based on season and hour of recharging. Fig. 6 maps marginal GHG emissions rates by time of day and month. The table elements represent average values for each hour of the day in a given month. The bottom row represents the vehicle demand-weighted marginal GHG emissions rate averaged over all hours of the month or year. This example represents BEVs recharging according to the *Offpeak* profile using assumptions from the base case. Each pathway and timing profile will have a unique emissions map.

In this case, a BEV recharged during early morning hours in the spring will have emissions that are about 20% lower than the annual average. Its emissions are about 20% higher than average if recharged during summer afternoons. Altogether, emissions are relatively low during early morning hours, when demand is low, and especially during spring months, when hydro-generation is abundant. Emissions are relatively high in the afternoon and during the summer, when demand is high. Also, emissions are high in the early winter, when hydro-generation is low, many power plants

[5] Referring to Fig. 4, all pathways with similar timing profiles have similar marginal generation and emissions rates, given the relatively small marginal demand considered here. So the results in Fig. 5 are typical for any pathway following one of the three timing profiles in the near term.

Hour	Avg. recharging demand (MW)	J	F	M	A	M	J	J	A	S	O	N	D	Year
0	307	630	548	612	531	494	564	638	646	608	634	586	641	595
1	307	634	544	589	517	502	548	570	633	583	623	547	630	577
2	276	619	535	586	507	515	530	546	614	571	595	549	630	567
3	184	623	539	588	512	509	543	541	618	576	589	552	629	569
4	123	639	562	609	535	510	546	569	618	596	622	573	639	585
5	61	646	615	632	592	509	543	610	644	630	636	625	653	611
6	31	654	633	640	600	566	600	614	652	639	638	612	640	624
7	15	657	638	644	639	615	616	650	673	654	656	640	641	644
8	15	665	642	661	644	631	651	667	684	672	654	654	652	657
9	46	665	648	653	650	657	667	682	679	679	655	659	660	663
10	77	654	648	661	661	677	681	684	692	673	674	666	662	670
11	77	658	649	665	670	676	681	707	715	694	667	659	664	676
12	77	658	651	658	667	678	687	714	721	710	658	659	663	677
13	77	658	654	658	667	675	685	721	743	699	672	656	652	679
14	77	655	643	660	661	685	688	745	742	691	675	656	658	680
15	31	648	645	669	658	676	690	750	721	712	681	659	654	680
16	15	657	646	653	652	678	683	732	736	699	671	663	658	678
17	15	687	680	656	658	673	679	710	774	704	669	669	671	686
18	61	687	680	666	660	665	668	696	725	699	680	669	685	682
19	123	678	667	670	671	686	679	693	704	705	675	664	672	681
20	184	673	662	660	662	681	687	675	695	683	670	656	666	673
21	276	660	660	662	659	670	681	687	693	680	656	647	664	668
22	307	654	629	636	627	600	695	660	666	663	654	634	661	648
23	307	647	576	625	555	510	590	658	659	645	632	632	648	615
Demand-weighted avg.		647	601	629	590	580	617	639	665	640	640	613	650	626

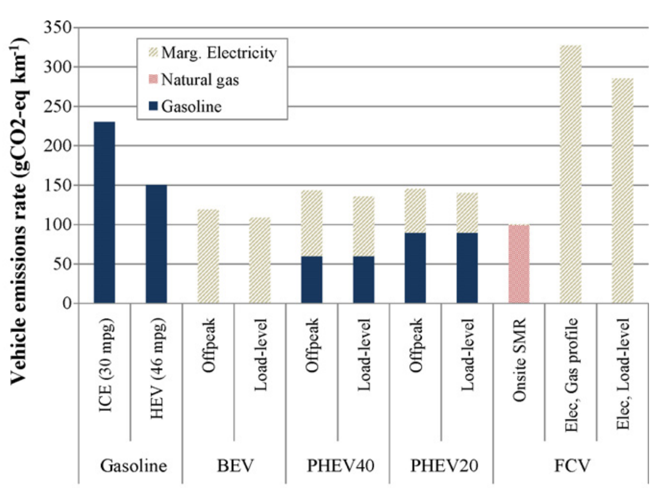
Average hourly marginal generation GHG emissions rate (gCO_2-eq kWh^{-1}): colour scale 494 – 634 – 774

Fig. 6. Map of marginal electricity GHG emissions rates by hour of day and month (BEVs, *Offpeak* profile.).

undergo maintenance, and peak demands in the Northwest limit the availability of system imports.

4.3. Vehicle emissions

After marginal GHG emissions rates from the electricity sector are determined, well-to-wheels vehicle emissions are calculated. They are compared in Fig. 7, and represent the produce of vehicle energy intensity (calculated from the fuel economy values given in Table 1) and fuel carbon intensity. Carbon intensity includes pathway contributions from gasoline, marginal electricity, and natural gas (also shown in Table 1).



	ICE (30 mpg)	HEV (46 mpg)	BEV Offpeak	BEV Load-level	PHEV40 Offpeak	PHEV40 Load-level	PHEV20 Offpeak	PHEV20 Load-level	Onsite SMR	Elec, Gas profile	Elec, Load-level
MJ km^{-1}	2.39	1.57	0.68		1.10		1.25		1.03		
gCO_2 MJ^{-1}	96.0	96.0	174.0	158.7	130.0	123.1	115.9	111.8	97.2	317.1	276.2

Fig. 7. Well-to-wheels vehicle emissions (gCO_2 equiv. km^{-1}) by energy source, vehicle energy intensity (MJ km^{-1}), and fuel carbon intensity (gCO_2 equiv. MJ^{-1}) by vehicle pathway and timing profile.

All of the pathways except for FCVs using hydrogen from electrolysis reduce GHG emissions compared to ICEs and HEVs. Fuel cell vehicles using hydrogen from SMR and BEVs recharging according to the *load-level* profile reduce emissions the most, by more than 25% compared to HEVs. Battery-electric vehicles recharging according to the *Offpeak* profile reduce emissions by 21% compared to HEVs. Driving a PHEV20 offers little emissions improvement compared to HEVs, only 3% in the *Offpeak* profile and 6% for the *load-level* profile.

As seen by the carbon intensity values in Fig. 7, the reduction in emissions from advanced electric-drive vehicles in the near-term is a result of improved vehicle efficiency, rather than reduced carbon intensity of fuel. None of the pathways here use "low carbon fuel," compared to gasoline in the near term (although there is potential to do so in the future). In the base case of BEVs recharging according to the *Offpeak* profile, for example, the carbon intensity of electricity is 80% higher than that of gasoline, but BEVs use less than half as much energy, and are lower emitting than HEVs.

4.4. Policy implications

These findings counter the assumptions for marginal electricity included in the LCFS rulemaking. The statue assumes that marginal electricity comes from NGCC plants (79%) and renewable power (21%), with a GHG emissions rate of 104.7 gCO_2 equiv. MJ^{-1}, or 377 gCO_2 equiv. kWh^{-1} [71].

But in the near-term, the likely marginal mix and GHG emissions rate will be quite different. Renewable power does not operate on the margin and marginal generation from dispatchable power plants is unlikely to come entirely from NGCC plants operating with average heat rates. Rather, NGCT plants will supply an important fraction of marginal generation, and when NGCC plants do operate on the margin, they will likely have a higher heat rate and GHG emissions rate than average NGCC generation.

Assuming that the *Offpeak* profile represents likely near-term charging, the results here suggest that the marginal generation mix will be about 63% from NGCC plants and about 37% from NGCT plants, and marginal emissions rates will be more than 65% higher than in the LCFS. Vehicle emissions, then, are underestimated by a similar fraction for BEVs, and by 11–25% for the PHEV pathways. These findings, as discussed, are sensitive to a number of parameters.

5. Conclusions

This paper describes the EDGE-CA model and applies it to investigate operation of the California grid in response to added vehicle and fuel-related electricity demand in the near term. Specifically, the marginal generation mix and GHG emissions rate supplying various vehicle and fuel pathways are identified. Impacts on well-to-wheels vehicle GHG emissions are quantified, and sensitivities to hydro-availability, demand timing, and demand location are explored.

In the near-term, electricity demand from vehicle and fuel pathways will contribute very little to electricity demand in the state. If PHEVs or BEVs were to account for 1% of VMT in 2010, electricity demand would increase by 0.1–0.3%. In the worst case considered here, were FCVs using grid electrolysis to provide 1% of VMT, electricity demand would increase by 0.8%.

Generators operating on the margin are likely to be natural gas-fired, but not all NGCC plants, as often assumed. Under the most basic assumptions, almost 40% of marginal generation for vehicle recharging will come from relatively inefficient NGCT plants. The marginal generation mix is highly sensitive to a number of parameters, however, and the fraction of marginal generation from NGCT plants may range from 20 to 40% for BEV and PHEV scenarios in a given month.

Marginal GHG emissions rates from the electricity sector range from 525 gCO_2 equiv. kWh^{-1} to 670 gCO_2 equiv. kWh^{-1} in the scenarios and sensitivity analyses considered here. According to the most likely vehicle recharging profile (*Offpeak*), annual average GHG emissions rates from marginal generation are likely to be about 625 gCO_2 equiv. kWh^{-1}. Marginal emissions are sensitive to time of day and season, and are lowest during early morning hours and in the spring. They are highest in the afternoon and during summer and early winter months.

Marginal electricity in California is more carbon-intensive than gasoline. But electric-drive vehicles are more efficient than ICEs and HEVs. In most cases, the improved efficiency of electric-drive trains outweighs the difference in fuel carbon intensity, and the vehicles considered here reduce GHG emissions compared to HEVs. The exception is FCVs with hydrogen from electrolysis using the near-term marginal generation mix, which increase emissions even compared to conventional ICE vehicles. Fuel cell vehicles using hydrogen from SMR and BEVs reduce vehicle emissions the most. For plug-in vehicles, increasing the fraction of all-electric driving increases electricity consumption onboard the vehicle, and thus the overall carbon content of fuel used. But it also increases vehicle efficiency and reduces GHG emissions.

The results here suggest that the assumptions included in the LCFS misrepresent marginal generation for vehicles in California in the near term. Under the assumptions of this analysis, the LCFS underestimates near-term marginal GHG emissions rates by at least 40%, and likely by more than 60%.

The results presented in this paper describe the emissions implications of using electricity as a fuel or as an input for hydrogen production from the current grid. Over time, the carbon intensity of the grid will decrease, as energy policies promote renewable generation or impose costs on GHG emissions, and as older power plants are retired and replaced with newer, more efficient ones. In the future, the carbon content of electricity supplying vehicles and fuels could be much lower than it is currently.

Increasing the use of plug-in vehicles or FCVs is one of the most promising methods for reducing petroleum consumption and GHG emissions from the transportation sector. Understanding the operation of the grid and accurately assessing GHG emissions associated with electricity generation is important for calculating the true well-to-wheels emissions of different vehicle types, which is essential for policy and regulatory development. The EDGE-CA model provides a useful tool for investigating the response of the electricity system to demand and matches well with current system operation. It provides useful results appropriate for high-level analysis of GHG emissions from electricity supply in California. Additional analysis could improve understanding of generation and emissions in a GHG-constrained future, especially regarding the composition of future grids and opportunities for vehicle and fuel-related electricity demands to complement electricity supply.

Acknowledgements

The authors would like to thank the California Energy Commission, CH2M Hill, and the sponsors of the Hydrogen Pathways Program and the Sustainable Transportation Energy Pathways (STEPS) Program at the Institute of Transportation Studies at UC Davis for financial support.

References

[1] C. Yang, D. McCollum, R. McCarthy, W. Leighty, Transportation Research Part D: Transport and Environment 14 (3) (2009) 147–156.
[2] ARB, Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard, California Air Resources Board, 2009.
[3] M.A. Weiss, J.B. Heywood, E.M. Drake, A. Schafer, F.F. AuYeung, On the Road in 2020: A Life-Cycle Analysis of New Automobile Technologies, MIT EL 00-003, MIT Energy Laboratory, 2000.
[4] M. Granovskii, I. Dincer, M.A. Rosen, Journal of Power Sources 159 (2) (2006) 1186–1193.
[5] N. Brinkman, M. Wang, T. Weber, T. Darlington, Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions and Criteria Pollutant Emissions, Argonne National Laboratory, 2005.
[6] R. Edwards, J.-F. Larive, V. Mahieu, P. Rouveirolles, Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context (Version 2b), European Commission, 2006.
[7] A. Elgowainy, A. Burnham, M. Wang, J. Molburg, A. Rousseau, Well-to-Wheels Energy Use and Greenhouse Gas Emissions Analysis of Plug-in Hybrid Electric Vehicles, ANL/ESD/09-2, Argonne National Laboratory, 2009.
[8] A. Bandivadekar, K. Bodek, L. Cheah, C. Evans, T. Groode, J. Heywood, E. Kasseris, M. Kromer, M. Weiss, On the Road in 2035: Reducing Transportation's Petroleum Consumption and GHG Emissions, LFEE 2008-05 RP, MIT Laboratory for Energy and the Environment, 2008.
[9] M. Kromer, J. Heywood, Electric Powertrains: Opportunities and Challenges in the U.S. Light-Duty Vehicle Fleet, LFEE 2007-03 RP, MIT Laboratory for Energy and the Environment, 2007.
[10] M. Wang, Y. Wu, A. Elgowainy, Operating manual for GREET: Version 1.7, ANL/ESD/05-3, Argonne National Laboratory, 2007.
[11] W.G. Colella, M.Z. Jacobson, D.M. Golden, Journal of Power Sources 150 (2005) 150–181.
[12] ANL, The Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model, Argonne National Laboratory, 2009.
[13] NRC, The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs, National Research Council and National Academy of Engineering, The National Academies Press, Washington, DC, 2004.
[14] M.A. Delucchi, A Lifecycle Emissions Model (LEM): Lifecycle Emissions from Transportation Fuels, Motor Vehicles, Transportation Modes, Electricity Use, Heating and Cooking Fuels, and Materials (Documentation of methods and data), UCD-ITS-RR-03-17, Institute of Transportation Studies, UC Davis, 2003.
[15] ARB, Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG) (Version 2.1), California Air Resources Board, 2009.
[16] EPA, Emissions and Generation Resource Integrated Database (eGRID2007, Version 1.1), U.S. Environmental Protection Agency, 2009.

[17] NRC, Transitions to Alternative Transportation Technologies – A Focus on Hydrogen, National Research Council and National Academy of Engineering, The National Academies Press, Washington, DC, 2008.
[18] R.W. McCarthy, C. Yang, J.M. Ogden, Interactions between electric-drive vehicles and the power sector in California, in: 24th International Electric Vehicle Symposium and Exposition, Stavanger, Norway, 2009.
[19] S.W. Hadley, A. Tsvetkova, Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation, ORNL/TM-2007/150, Oak Ridge National Laboratory, 2008.
[20] A. Ford, Energy Policy 22 (7) (1994) 555–570.
[21] A. Ford, Energy and Buildings 22 (3) (1995) 207–218.
[22] J. Garland, S. Tomashefsky, Electric Vehicle and Power Plant Emissions Update: South Coast Air Basin, California Energy Commission, 1996.
[23] P. Denholm, W. Short, An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles, NREL/TP-620-40293, National Renewable Energy Laboratory, 2006.
[24] M. Kintner-Meyer, K. Schneider, R. Pratt, Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids: Part 1: Technical Analysis, Pacific Northwest National Laboratory, 2007.
[25] C.H. Stephan, J. Sullivan, Environmental Science and Technology 42 (4) (2008) 1185–1190.
[26] D.M. Lemoine, D.M. Kammen, A.E. Farrell, Environmental Research Letters 3 (1) (2008) p014003.
[27] J. Danforth, Plug-in hybrid charging in Los Angeles: analysis of the load-leveling capacity for charging plug-in hybrids in the Los Angeles Department of Water and Power transmission area, in: 23rd International Electric Vehicle Symposium and Exposition, Anaheim, CA, 2007.
[28] EPRI, NRDC, Environmental Assessment of Plug-In Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions 1014641, Electric Power Research Institute, 2007.
[29] EPRI, NRDC, Environmental Assessment of Plug-In Hybrid Electric Vehicles, Volume 2: United States Air Quality Analysis Based on AEO-2006 Assumptions for 2030, 1015325, Electric Power Research Institute, 2007.
[30] M.J. Scott, M. Kintner-Meyer, D.B. Elliott, W.M. Warwick, Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids: Part 2: Economic Assessment, Pacific Northwest National Laboratory, 2007.
[31] K. Parks, P. Denholm, T. Markel, Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory, NREL/TP-640-41410, National Renewable Energy Laboratory, 2007.
[32] ANL, Impact of Plug-in Hybrid Electric Vehicles on the Electricity Market in Illinois, Argonne National Laboratory, 2008.
[33] C. Samaras, K. Meisterling, Environmental Science and Technology 42 (9) (2008) 3170–3176.
[34] J. Kliesch, T. Langer, Plug-In Hybrids: An Environmental and Economic Performance Outlook, American Council for an Energy-Efficient Economy, 2006.
[35] C. Quinn, D. Zimmerle, T.H. Bradley, Journal of Power Sources 195 (5) (2010) 1500–1509.
[36] W. Kempton, J. Tomic, Journal of Power Sources 144 (1) (2005) 280–294.
[37] W. Kempton, J. Tomic, Journal of Power Sources 144 (1) (2005) 268–279.
[38] J. Tomic, W. Kempton, Journal of Power Sources 168 (2) (2007) 459–468.
[39] B.D. Williams, K.S. Kurani, Journal of Power Sources 166 (2) (2007) 549–566.
[40] CEC, Summer 2007 Electricity Supply and Demand Outlook, CEC-200-2007-005-SD, California Energy Commission, 2007.
[41] CAISO, System Load and Resource Schedules (Hour Ahead Market) Open Access Same-Time Information System (OASIS), California Independent System Operator, 2008.
[42] WECC, Information Summary, Western Electricity Coordinating Council, 2006.
[43] A. Alvarado, K. Griffin, Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports (Update to the May 2006 Staff Paper) CEC-700-2007-007, California Energy Commission, 2007.
[44] CEC, California Major Utilities' Resource Mix for 2006, California Energy Commission.
[45] CEC, Electricity Consumption by Entity, California Energy Commission, 2008.
[46] FERC, Form 714 – Annual Electric Balancing Authority Area and Planning Area Report, Federal Energy Regulatory Commission, 2008.
[47] R.W. McCarthy, C. Yang, J.M. Ogden, California Energy Demand Scenario Projections to 2050, UCD-ITS-RR-08-11, Institute of Transportation Studies, University of California, Davis, 2006.
[48] DOE, DOE H2A Production Analysis, U.S. Department of Energy, 2005.
[49] Nexant, Hydrogen Delivery Infrastructure Option Analysis, DOE and Freedom CAR & Fuel Partnership Hydrogen Delivery and On-Board Storage Analysis Workshop, Washington, DC, 2005.
[50] EIA, Petroleum Consumption/Sales Data and Analysis, Energy Information Administration, 2009.
[51] NERC, Electricity Supply and Demand (ES&D 2007), North American Electric Reliability Corporation, 2007.
[52] EPA, National Electric Energy Data System (NEEDS) 2006, U.S. Environmental Protection Agency, 2006.
[53] EIA, Proposed Nameplate Capacity by Year, Energy Source, and State (EIA-860), Electric Power Annual with Data for 2007, Energy Information Administration, 2009.
[54] CAISO, Open Access Same-time Information System (OASIS), California Independent System Operator, 2008.
[55] NERC, 2002–2006 Generating Availability Report, North American Electric Reliability Corporation, 2007.
[56] CAISO, Market Issues & Performance: 2007 Annual Report, California Independent System Operator Corporation, 2008.
[57] CEC, 1983–2006 California Electricity Generation (spreadsheet), California Energy Commission, 2007.
[58] CEC, 2007 Net System Power Report, CEC-200-2008-002-CMF, California Energy Commission, 2008.
[59] EIA, Form EIA-906, EIA-920, and EIA-923 Databases, Energy Information Administration, 2009 (accessed 3.02.09).
[60] NREL, National Solar Radiation Database, National Renewable Energy Laboratory (accessed 30.07.08).
[61] T.E. Lipman, R. Ramos, D.M. Kammen, An Assessment of Battery and Hydrogen Energy Storage Systems Integrated with Wind Energy Resources in California, CEC-500-2005-136, California Energy Commission, 2005.
[62] B. Smith, G. Randall, T. McCoy, J. VandenBosche, Power Performance Testing Progress in the DOE/EPRI Turbine Verification Program, NREL/CP-500-30667, National Renewable Energy Laboratory, 2001.
[63] Energy and Environmental Economics, Inc, Attributing Generator Emissions to LSEs (Supporting documentation to the CPUC GHG modeling), 2007.
[64] Energy and Environmental Economics, Inc, Generator Assignment in E3 Model.xls (Supporting documentation to the CPUC GHG modeling), 2008.
[65] EIA, Net Generation by State by Type of Producer by Energy Source (EIA-906), Energy Information Administration, 2009 (accessed 6.02.09).
[66] J. Klein, A. Rednam, Comparative Costs of California Central Station Electricity Generation Technologies, CEC-200-2007-011, California Energy Commission, Electricity Supply Analysis Division, 2007.
[67] AWEA, US Wind Energy Projects – California (As of 12/31/2008), American Wind Energy Association, 2009.
[68] EIA, Electric Power Annual 2007, Energy Information Administration, 2009.
[69] NCDC, Heating & Cooling Degree Day Data, National Climatic Data Center, NOAA Satellite and Information Service, 2008 (accessed 1.10.08).
[70] J. Woodward, Dependable Hydro Capacity, Summer 2008, Electricity Supply and Demand Outlook Workshop, California Energy Commission, 2008.
[71] ARB, Detailed California-modified GREET Pathway for California Average and Marginal Electricity (Version 2.1), California Air Resources Board, 2009.
[72] A. Alvarado, Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports, CEC-700-2006-007, California Energy Commission, 2006.
[73] EIA, Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906), Energy Information Administration, 2009.
[74] EPA, eGRID Year 2005 Summary Tables, U.S. Environmental Protection Agency, 2008.