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Interactions between electric-drive vehicles and the power sector in California

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Abstract

This paper explores the implications of vehicle recharging on the current electricity grid in California and compares well-to-wheel vehicle emissions for various vehicle and fuel platforms at different times of day and during different seasons. An hourly electricity dispatch model that accounts for supply, demand, and energy transfers among three regions in the state is used to determine the last generator operating in any given hour for a simulated grid and demand curve in 2010. Emissions rates from these generators are attributed to vehicle demand. Plug-in hybrid vehicles are found to reduce emissions compared to conventional hybrids if recharged anytime except during the 2% of hours with the highest marginal electricity emissions rates. This threshold is roughly equal to the emissions rate from an average natural gas combustion turbine (peaking plant) plant operating in California. Battery-electric and fuel cell vehicles using hydrogen from natural gas reformation reduce emissions further. The paper also compares likely near-term marginal greenhouse gas emissions rates from the electricity sector to assumed values in California's Low Carbon Fuel Standard, and finds that the Statute significantly underestimates likely near-term marginal emissions from the sector, and resulting emissions from plug-in vehicles.

Keywords: electricity, emissions, fuel, load management, PHEV

1 Introduction

Comparing emissions from plug-in vehicles to those from other vehicle types requires analysis on a "well-to-wheels" (WTW) basis. Well-to-wheels emissions include those upstream from the vehicle, from the "well-to-tank", as well as those that take place from the "tank-to-wheels". Emissions from conventional gasoline vehicles and hybrids occur predominately from the tank to the wheels; only a small fraction of the emissions associated with operating the vehicle occur during the extraction, refining, and transportation of gasoline to a vehicle's tank. In a plug-in vehicle, the well-to-tank emissions associated with generating electricity comprise an important component of total WTW emissions. In the case of a battery-electric vehicle (BEV) or hydrogen fuel cell vehicle (FCV), the WTW emissions are entirely those that occur upstream from the vehicle's "tank".

Characterizing these upstream emissions for BEVs or plug-in hybrid electric vehicles (PHEVs) requires understanding which power plants are operating during vehicle recharging that would not be generating power otherwise. This mix of power plants is often referred to as the marginal generation mix for vehicles, which more accurately captures the impact of vehicle demand on the electricity grid than attributing emissions from the average grid mix to vehicle demand. Existing coal, nuclear, wind, solar, and hydro plants will generate the same amount of electricity with or without vehicle demands. Dispatchable thermal power plants that follow load will supply demand on the margin, and the marginal mix comprises the last set of power plants to be brought online during any period of vehicle recharging. They will typically be the most expensive, and perhaps least efficient, plants operating at the time. Consequently, the marginal greenhouse gas (GHG) emissions rate from power plants supplying plug-in vehicles may differ significantly from the average GHG emissions rate from all of the plants operating at a given time.

This paper explores the implications of vehicle recharging on the current electricity grid in California and compares WTW vehicle emissions for various vehicle and fuel platforms. It also compares likely near-term marginal GHG emissions rates from the electricity sector to assumed values in California's Low Carbon Fuel Standard (LCFS), and finds that the Statute likely underestimates emissions from the sector.

2 Description of the California Electricity Dispatch Model (CED)

The California Electricity Dispatch (CED) model is a tool developed at the University of California, Davis by the authors to investigate vehicle demand impacts on electricity supply and GHG emissions [1, 2]. It is a spreadsheet-based accounting tool that allocates generation among available power plants on an hourly basis to meet demand. The model represents supply, demand, and energy transfers among three regions in California – Northern California (CA-N), Southern California (CA-S), and the Los Angeles Department of Water and Power (LADWP) service territory – as well as imported power from out of state. It includes variable power plant availability that differs based on hourly, daily, and seasonal factors, and accounts for scheduled and unscheduled power plant outages.

The model "dispatches" power plants in a specified order to meet hourly demands. Nuclear, renewable, and firm imports power are treated as "must-run", and are taken whenever available. ("Firm imports" refer to energy from out-of-state power plants that are owned by utilities within California. Those power plants are mostly coal-fired facilities located in the southwestern United States. "System imports" refer to power available for purchase in real time, and mostly come from natural gas plants in the Southwest, and hydro plants in the Northwest [3, 4].) Hydro power is allocated to reduce dispatchable capacity requirements during daytime and peak demand hours. System imports are represented based on regression analyses that define hourly import availability in terms of supply and demand characteristics in California and nearby states. The remaining power plants are dispatched in order of increasing operating cost, when they are available.

Supply curves are constructed for each geographic region, according to the dispatch rules above, and generation is allocated among power plants to minimize hourly costs, subject to transmission constraints among the regions. Power transfers can occur between CA-N and CA-S (up to 3000 MW in either direction) and between CA-S and LADWP (up to 1000 MW in either direction). If transmission constraints are reached, one or two regions will have power plants operating that are more costly than power that would otherwise be available from another region.

A representative supply curve for the state is shown in Figure 1. The figure also depicts GHG emissions rates associated with the last generator that would be brought online at each level of demand. Marginal costs depend on operating expenses only. Generally, the emissions rate of power plants increases with marginal costs. At the low end of the curve, hydro, nuclear, and renewable generators operate with essentially zero operating costs and emissions. Moving up the supply curve, firm imports from out-of-state coal plants operate with high GHG emissions, followed by system imports from the Northwest (NW imports). The remaining plants are mostly natural gas-fired, whose costs and emissions generally increase with heat rate.

Importantly, the model tracks the last power plant dispatched. This "marginal" generator sets the market clearing price for electricity, and its characteristics are attributable to incremental demand. When new demand from vehicles is imposed on an existing system, the characteristics of the marginal electricity that would not be generated otherwise determine the costs and emissions associated with using electricity as fuel.

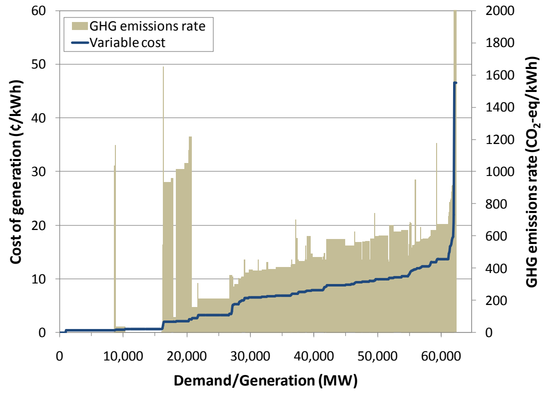

Figure 1: Representative California-wide electricity supply curve based on variable operating costs, including imported power

Sample outputs from CED are illustrated in Figure 2, which depicts results from a simulation for 2010, based on a demand curve from [5] and the current grid (plus expected near-term renewable capacity additions [6]). The model accounts for generation by resource type and hourly costs and emissions state-wide and by region. Both average GHG emissions rates and the marginal emissions rate from the last plant serving each region are shown. Interestingly, emissions rates do not always peak with demand. During some of the days depicted, GHG emissions rates are higher during "shoulder" demand hours than they are on-peak, when hydro power plants are operating at full capacity.

Power plants operating in the CA-S region are often the last generator online in the state, especially during months with relatively high hydro availability – as is the case for the spring week shown here – since CA-S controls a small fraction of California hydro generation relative to its demand. So in this case, market-clearing prices and marginal generator emissions on a state-wide basis match the lines for CA-S closely.

Power plants are represented in CED primarily based on data from the U.S. EPA's eGRID database [7]. The database provides plant-level data for U.S. power plants operating in 2005. Importantly, it includes capacity, generation, heat rate, and emissions rate 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 NERC, which are included in the CED model. Data from eGRID is supplemented with information from NERC's Electricity Supply and Demand (ES&D) database [8] and the U.S. EPA's National Electric Energy Data System (NEEDS) [9] to help categorize power plant type, location, and ownership.

The composition of the California grid is characterized in Table 1. Instate power plants are classified according 13 categories. Natural gas-fired power plants comprise over 60% of capacity and almost 50% of generation. Hydro plants account for about 20% of capacity, and in 2005, a similar fraction of generation. California's two nuclear plants represent 8% of capacity, but provide 19% of generation. The balance of instate capacity and generation comes from renewables and a few, small coal and oil-fired plants.

Generation from within California's borders only accounted for about two-thirds of annual consumption in 2005. Another 93,000 MW was imported from other states. Firm imports accounted for about half of imports, while system imports comprised the remainder of California's generation mix.

From the model accounting, comparative analyses are made. Impacts of demand timing on the operation of different types of power plants are investigated. Costs, emissions, and resource use are compared for different electricity demand profiles. And the model is applied to consider the effects of intermittent and variable availability of power plants on the system.

It is important to note the limitations of the CED model. In reality, sophisticated decision-making algorithms are used by grid operators to dispatch generation optimally. Their models rely on proprietary data and software, and take into account several important considerations that are not included here, including:

- Local transmission and distribution constraints,
- Reliability constraints,
- Emissions constraints,
- Operational constraints of power plants, such as minimum loading, start-up and shutdown costs, and ramp rates, and
- Impacts of dispatchable power plant outages on hydro generation and imports.

The CED model does not replicate such algorithms. But it does capture the *types of power plants* that operate throughout the State quite accurately, providing useful metrics for analysis. In back-casts for 2005-2007 used to validate the model, CED matched historical generation data by power plant type within ±3% for each resource. Deviations from the data that did exist tend to underestimate electricity sector emissions, and it is assumed that average and marginal emissions rates reported here are slightly lower than reality.

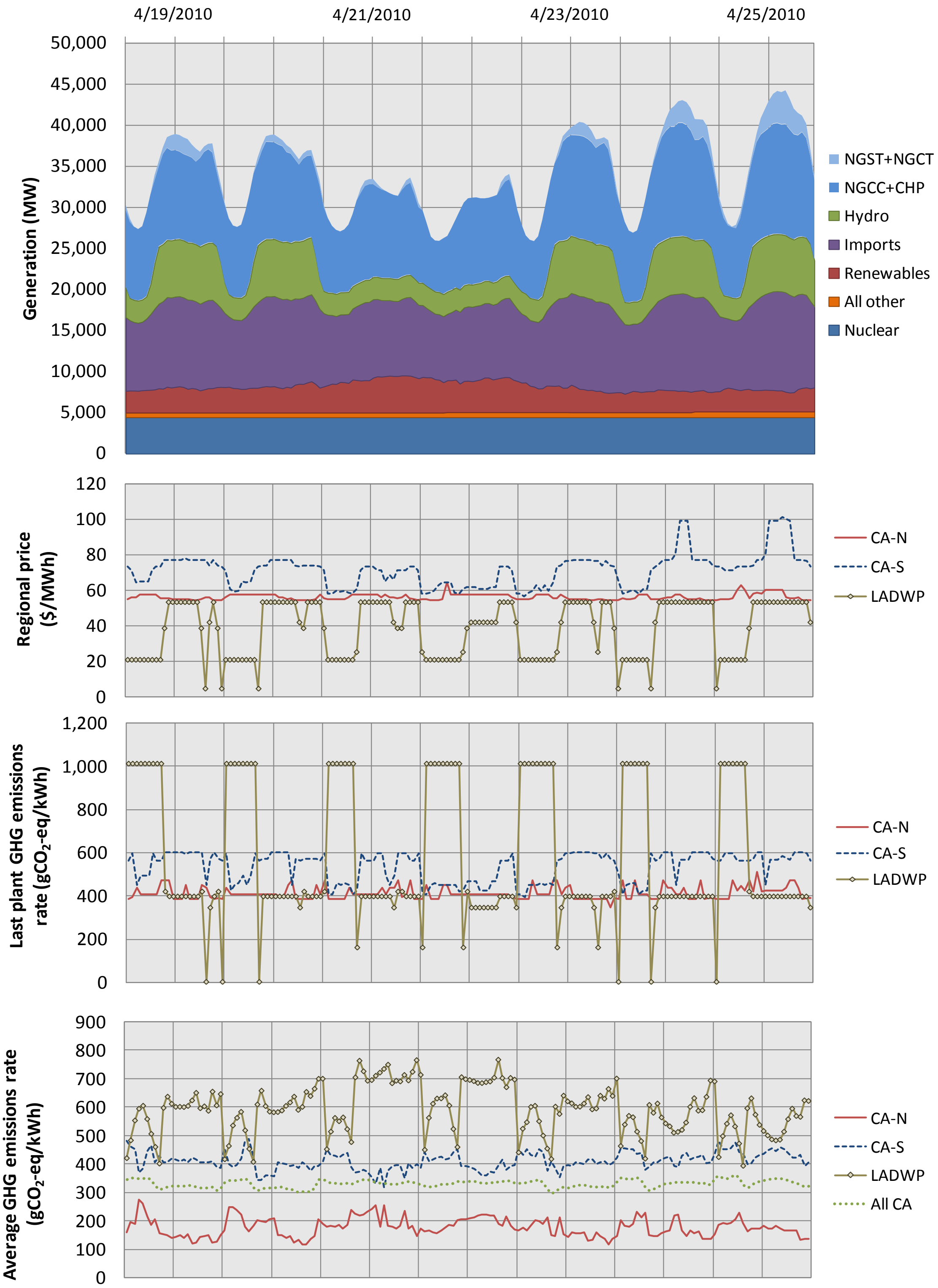

Figure 2: Sample outputs from the CED model

Table 1: Summary of California electricity supply (2005)

	Capacity, 2005 (MW)	Generation, 2005 (GWh)	Heat rate (Btu/kWh)	Variable cost ($/MWh)	GHG rate (g CO_2-eq/kWh)	Ownership fractions of capacity/generation CA-N	CA-S	LADWP
Nuclear	4,577	36,155	0	7.6	0	51%	49%	0%
Solar	402	624	1,787	17.8	95	0%	100%	0%
Wind	2,407	4,259	0	0.0	0	61%	39%	0%
Geothermal	2,162	9,211	0	5.5	37	85%	15%	0%
Biomass	1,516	7,180	12,509	26.7	156	64%	28%	8%
Coal	363	2,306	11,108	18.3	1,055	48%	52%	0%
Oil	568	2,166	10,957	13.8	1,030	86%	14%	0%
Other	49	193	398	4.5	6	8%	27%	65%
CHP	2,962	19,225	7,770	67.2	412	70%	27%	3%
Hydro	13,162	39,185	0	4.1	0	75%	19%	6%
NGCC	19,207	60,124	7,729	55.6	416	57%	25%	18%
NGST	7,796	4,479	11,363	80.3	624	42%	47%	11%
NGCT	10,099	9,888	11,407	97.1	616	28%	70%	2%
CA subtotal	65,269	194,994	4,708	34.4	246	---	---	---
Firm imports[1]	6,288	37,505	8,231	---	769	3%	57%	40%
Nuclear	1,153	7,071	0	---	0	0%	65%	35%
Coal	3,896	28,394	10,833	---	1,013	5%	49%	46%
Hydro	1,143	1,952	0	---	0	0%	72%	28%
Oil	95	88	12,548	---	679	0%	100%	0%
NW imports[2]	8,000	31,993	2,724	---	186	75%	25%	0%
Coal (8.8%)	---	2,815	11,184	---	1045	---	---	---
Nuclear (1.7%)	---	544	0	---	0	---	---	---
Hydro (66%)	---	21,148	0	---	0	---	---	---
Natural gas (22%)	---	7,039	7,910	---	426	---	---	---
Renewable (1.4%)	---	448	0	---	0	---	---	---
SW imports[2]	7,000	23,485	7847	---	439	0%	67%	33%
Coal (4%)	---	939	10,835	---	1010	---	---	---
Natural gas (96%)	---	22,545	7,723	---	415	---	---	---
Total[3]	---	287,977	5,203	---	323	---	---	---

CA-N = Northern California; CA-S = Southern California; CHP = Combined heat and power; GHG = Greenhouse gas emissions; LADWP = Los Angeles Department of Water and Power; NGCC = Natural gas combined-cycle; NGCT = Natural gas combustion turbine; NGST = Natural gas steam turbine; NW = Northwest, SW = Southwest

Unless noted, all plant data from [7-10]

[1] California firm imports shares from [11, 12]. Generation based on plant capacity factors in 2005, applied to CA utility shares

[2] System import capacity defined as transmission line capacity minus firm imports from each region [4, 13]; System import mix defined from [4]; 2005 generation from NW and SW imports estimated from average 2006-2007 net import fractions and scaled to required system imported generation (total generation minus instate generation and firm imports); Heat rates and emission rates are based on generation-weighted averages for NWPP and DSW regions [7]; Ownership fractions of 2005 generation from system imports estimated from [14, 15]

[3] Total generation for California in 2005 from [16]

3 California electricity supply in 2010

The mix of power plants supplying vehicles in the near term is investigated with CED based on an electricity demand curve from the EPA for 2010 [5]. Total generation required is 317,650 GWh, about 5% more than was required in 2007. Peak coincident demand is 57,093 MW, which is less than peak demands in 2006 and 2007. To the extent that the peak demand projection may be relatively low, peak required dispatchable capacity is comparatively low, as well, leading to lower peak costs and marginal GHG emissions rates than would otherwise exist.

It is assumed that in 2010 electricity supply in California will look similar to today. Renewable generator capacity will have increased slightly, to help utilities meet California's Renewable Portfolio Standard (RPS) requirement, and a few additional dispatchable power plants will have been built, and some retired. Hydro and nuclear capacities are unlikely to change, firm import contracts that exist today are likely to exist in the near future, and dispatchable natural gas-fired generators will provide a significant fraction of generation in the state. The representation of California electricity supply in CED should apply well to 2010, then.

Hydro availability is the primary variable – aside from demand quantity and timing – that determines the costs and emissions associated with California electricity supply. A distribution of annual hydro generation from 1983-2006 was used to determine the likelihood that a certain amount of the resource would be available in a given year [16]. The CED model was run for the 2010 case without vehicle demand and with various levels of annual hydro generation to determine the impact of hydro availability on electricity supply in California.

The results are summarized in Table 2. Variable hydro conditions affect natural gas generation and the level of system imports. (Firm imports vary slightly because energy from Hoover Dam scales with California hydro generation in CED.)

In a 1-in-10 dry hydro year, 47% of lost hydro generation compared to median values is balanced with additional system imports, in about equal quantities form the Northwest and Southwest. Natural gas combined cycle and combined heat and power (NGCC+CHP) plants make up 37% of the lost generation, and steam and combustion turbines (NGST+NGCT) comprise the balance.

In very wet years, system imports decline compared to their median values by a similar fraction as they increase in dry years (the import regressions scale linearly with California hydro generation). Among natural gas plants, abundant hydro mostly displaces intermediate NGCC+CHP generation. Half of the extra hydro generation in the 90th percentile case, compared to the median case, displaces NGCC+CHP generation, and only 3% of it offsets NGST+NGCT generation, because peak hydro capacity is held constant. Adding hydro does little to change peak dispatchable capacity requirements, so operation of peaking natural gas plants changes little in wet years. But dry years reduce the number of hours during which peak hydro capacity is available, increasing the number of hours during which NGCT and NGST plants are needed and total generation from those less-efficient power plants.

Median marginal electricity costs decrease slightly with increasing levels of hydro generation. They change most noticeably in the LADWP region, where dispatchable generation is much more expensive than relatively low-cost coal and hydro generation that comprise a large portion of supply in the region. Prices in CA-S change very little.

Table 2: California electricity supply in 2010 with variable hydro availability

		NW and CA hydro availability (percentile)				
		10th	25th	50th	75th	90th
Generation (GWh)	Nuclear	38,306	38,306	38,306	38,306	38,306
	Renewables	28,192	28,192	28,192	28,192	28,192
	Firm Imports	43,408	43,868	44,378	44,889	45,349
	NW imports	24,307	22,706	20,927	19,148	17,546
	SW imports	27,403	25,797	24,014	22,230	20,625
	Hydro	24,235	30,546	37,557	44,569	50,879
	NGCC+CHP	112,240	110,275	107,126	103,358	100,089
	NGST+NGCT	14,614	13,015	12,202	12,006	11,710
	Other	4,944	4,945	4,948	4,953	4,954
Average price ($/MWh)	CA-N	78.7	77.6	76.7	75.6	74.5
	CA-S	94.2	94.0	93.8	93.7	93.4
	LADWP	65.3	65.0	64.3	63.6	62.9
Average emissions rate (gCO_2-eq/kWh)	CA-N	239	226	211	197	185
	CA-S	477	468	459	450	441
	LADWP	671	665	658	653	646
	All CA	395	385	373	363	353
Marginal emissions rate (gCO_2-eq/kWh)	12am-6am	515	517	515	506	494
	6am-12pm	574	572	564	559	555
	12pm-6pm	595	594	592	591	591
	6pm-12am	592	588	588	588	588

Average GHG emissions rates change most in Northern California, where the hydro resource is most abundant. There, the average GHG emissions rate fluctuates by ±13% from the median value based on hydro availability. The impact of hydro generation on emissions is less pronounced in other regions and state-wide, where average emissions rates during very wet or dry years vary by ±5% from the median value.

Marginal GHG emissions rates are higher than average emissions rates, because existing capacity of low-carbon hydro, nuclear, and renewable power operates regardless of whether there is vehicle demand for electricity. These resources are not allocated to vehicle and fuel demands. Therefore, electricity for vehicles and fuels will have higher GHG emissions rates associated with it than average electricity generation. Note that this will not be the case in regions with significant coal-fired power plant capacity, where natural gas plants likely operating on the margin have lower GHG emissions rates than coal power supplying non-vehicle demands.

Average hourly GHG emissions rates from the last generator operating in the state in 2010 are illustrated in Figure 3, assuming median hydro availability. The emissions rates depicted in the figure represent those that would go into a vehicle (or any other marginal demand), were it plugged in during a given hour in 2010.

Average marginal emissions rates track dispatchable capacity requirements. During afternoon hours in late summer, when demand is high and hydro availability may be low, emissions from power plants likely to supply vehicles are highest. During the early mornings of spring months, when demand is relatively low and hydro generation is relatively high, GHG emissions rates from the generator on the margin are lowest.

On average, GHG emissions rates from the last plant operating are highest in the 6:00-7:00pm hour. This time frame coincides with peak dispatch requirements during winter, spring, and fall months. In the summer, peak dispatch occurs a few hours earlier, but remains high into the evening. It also coincides with the end of evening rush hour, when – presumably – many electric vehicle owners will plug-in their vehicles. Emissions rates from marginal generators remain high through the evening, and do not decline significantly until after midnight. If GHG emissions are to be minimized, then, vehicles are usually best recharged between 1:00am and 7:00am.

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
0	612	612	589	546	535	604	609	617	614	598	585	623	595
1	614	600	555	484	493	578	571	594	574	570	534	605	564
2	600	578	528	467	510	539	529	557	542	538	498	590	540
3	609	553	525	475	512	519	515	525	510	515	482	582	527
4	609	572	549	481	515	532	516	531	523	540	505	592	539
5	610	607	561	493	513	527	519	575	565	581	559	612	560
6	613	609	580	514	511	543	554	584	572	587	575	610	571
7	610	610	604	531	529	564	588	594	604	597	600	611	587
8	625	620	615	563	584	602	598	620	629	622	607	621	609
9	627	633	613	596	589	614	615	626	631	628	616	629	618
10	630	635	625	603	621	633	634	639	626	618	620	625	626
11	623	640	625	612	639	644	629	635	647	638	626	618	631
12	632	633	626	609	628	639	650	645	643	632	625	630	633
13	622	637	620	621	630	642	650	662	643	637	631	626	635
14	628	637	626	607	625	652	661	686	644	657	633	627	640
15	627	630	627	606	640	650	651	681	662	643	625	620	639
16	623	633	631	600	626	658	642	662	675	635	630	631	637
17	638	636	626	604	641	652	657	663	661	635	625	621	638
18	642	635	624	608	644	639	655	653	666	646	635	642	641
19	651	634	621	615	640	639	636	655	662	638	626	629	637
20	629	612	634	621	622	629	644	655	652	637	631	631	633
21	637	634	614	619	623	643	642	632	643	647	630	653	635
22	629	628	624	617	629	640	631	647	634	631	624	621	630
23	613	612	609	597	604	623	628	643	634	616	610	619	617
Avg.	623	618	602	570	588	608	609	624	619	612	597	620	608

Figure 3: Average GHG emissions rate from last generator online (gCO_2-eq/kWh)

4 Vehicle emissions based on marginal generation and median hydro availability

Emissions from the last generator operating are applied to vehicle and fuel pathways based on the parameters listed in Table 3 to determine likely near-term vehicle emissions rates. Equivalent vehicle fuel economies are defined in relative terms compared to a baseline vehicle [17], which is assumed to achieve 30 mpg. Note that PHEV fuel economy only varies according to the all-electric fraction of driving. There is no accounting for effects of battery size and weight on fuel economy, and the only difference among PHEVs is their assumed fraction of miles travelled in all-electric mode. Also, no blended operation of PHEVs is considered.

Figure 4 depicts vehicle pathway GHG emissions based on the distribution of hourly marginal emissions rates. The figure illustrates vehicle emissions rates based on the distribution of emissions from the last generator operating in each hour of the year. Lower percentiles represent marginal electricity with lower-than average GHG intensity. Higher percentiles represent marginal electricity with higher GHG intensity. For example, the "25th percentile" value represents vehicle emissions associated with recharging during an hour in which the marginal generator has a lower GHG intensity than the one operating in 75% of hours of the year.

Given the current grid mix and the marginal generators likely to be operating, alternative vehicle and fuel pathways reduce GHG emissions compared to conventional hybrids. Emissions from PHEVs are always better than those from conventional hybrids below the 95th percentile level of marginal generator emissions. They tend to improve upon emissions from conventional hybrids further as the fraction of all-electric driving increases or emissions rates from the electricity sector decline. Emissions from BEVs are lower than those from PHEVs, but higher than those from FCVs using hydrogen derived from onsite natural gas steam-methane reformation (SMR) with marginal electricity emissions above the median rate. A FCV using hydrogen derived from electrolysis using marginal electricity emits more than a conventional hybrid, and usually, more than a conventional vehicle. If the grid evolves to include more renewable and low-carbon sources, however, emissions associated with operating electricity-intensive vehicles will decline accordingly.

The reduction in emissions found for electric-drive vehicles is a result of improved vehicle efficiency, rather than reduced carbon-intensity of fuel. (Electric-drive vehicles are 1.5-3.5 times more efficient than conventional gasoline cars.) The GHG content of marginal electricity given the current grid mix in California is greater than that for gasoline, which is assumed here to be 96 gCO_2-eq/MJ, or about 346 gCO_2-eq/kWh [18]. The GHG benefit of electric-drive cars depends on the electricity generation mix. At sufficiently high GHG-intensities, the increased carbon content of electricity negates efficiency gains from electric drivetrains, and EVs emit more GHGs than conventional hybrids.

Table 3: Vehicle and fuel pathway assumptions

	Scalar	mpgge[1]	All- electric fraction[2]	Gasoline use (gal/mi)	Electricity use (kWh/mi)[3]	NG use (Btu/mi)[3]
ICE	1.00	30.0	---	0.0333	---	---
HEV	1.53	45.9	---	0.0218	---	---
PHEV (ICE mode)	1.54	46.2	---	0.0216	---	---
PHEV (electric mode)	3.00	90.0	100%	---	0.371	---
PHEV10	1.64	49.1	12%	0.0190	0.045	---
PHEV20	1.91	57.4	40%	0.0130	0.148	---
PHEV40	2.18	65.3	60%	0.0087	0.223	---
BEV	3.50	105.0	---	---	0.318	---
FCV (electrolysis)	2.32	69.6	---	---	0.780	---
FCV (onsite SMR)	2.32	69.6	---	---	0.042	2250

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

[1] Relative vehicle efficiencies based on scalars from [17], and assuming a new baseline vehicle gets 30 mpg

[2] From [19], assuming 15,000 miles/vehicle/year

[3] Hydrogen pathway electricity intensity from DOE H2A analysis [20]

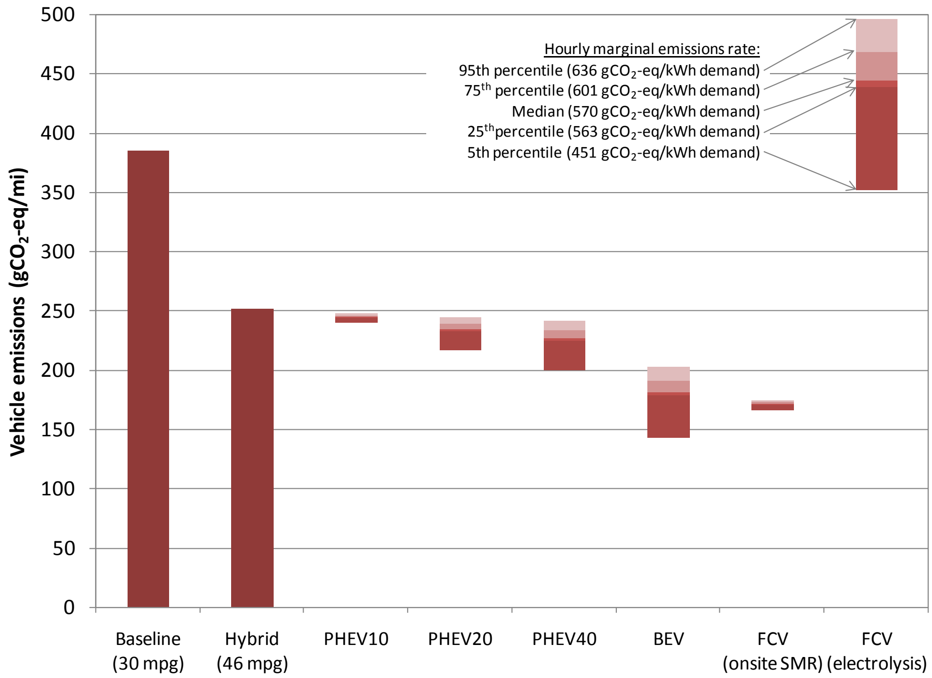

Figure 4: Vehicle pathway GHG emissions based on emissions rate from last generator online (median hydro)

Tradeoffs between efficiency and GHG intensity of electricity for advanced vehicles are illustrated in Figures 5 and 6. The figures show isolines of GHG emissions rates. The intersection of an alternative vehicle's energy intensity and an isoline corresponds to the required electricity sector emissions rate to achieve a given level of vehicle emissions. Electricity emissions below that level result in lower vehicle emissions than shown on the isoline.

Alternatively, for a given electricity sector GHG emissions rate, the electric energy intensity that leads to a target vehicle emissions rate can be determined. For reference, average GHG emissions rates from coal, natural gas combustion turbine (NGCT), and natural gas combined cycle (NGCC) plants are given, as well as the assumed electricity marginal generation mix in California's Low Carbon Fuel Standard (LCFS) [21].

In Figure 5, isolines are presented for electricity-only pathways, including BEVs and FCVs using hydrogen from electrolysis. Emissions from BEVs will essentially always be better than those from conventional vehicles. Even if an average coal plant powers a BEV, it will emit fewer GHGs than a conventional vehicle. In California, where coal is unlikely to supply plug-in vehicles, BEVs should be lower-emitting than conventional hybrids, as well. Even if the average peaking natural gas power plant (NGCT) supplies the electricity, emissions from the BEV will be less than those from conventional hybrids. Emissions from the last generator operating exceed 785 gCO_2-eq/kWh only during a single hour of a median hydro year in CED simulations. Above that level, emissions from BEVs exceed those from conventional hybrids. At the level of an average NGCC plant, emissions from BEVs are slightly less than 150 gCO_2/mi, and improve at emissions rates lower than that level.

Fuel cell vehicles using hydrogen derived from grid electrolysis are more than twice as energy intensive as BEVs, and electricity emissions must be less than half those for BEVs to achieve similar emissions per mile of driving. For emissions from a FCV to be less than those from a conventional vehicle, the marginal mix for electrolysis must have an average GHG intensity just above the average NGCC plant operating in the state. Such rates occur during 18% of hours in simulations for a median hydro year. During only one hour of the year, marginal generator emissions are low enough that electrolysis reduces vehicle emissions compared to hybrids.

Figure 6 depicts isolines for PHEV emissions, based on electricity sector emissions and fractions of all-electric miles driven (or equivalent fuel economy). Emissions from a conventional hybrid are essentially the same as those from a PHEV not operating in all-electric mode, and the hybrid isoline creates an asymptote below which increased all-electric driving is beneficial from a

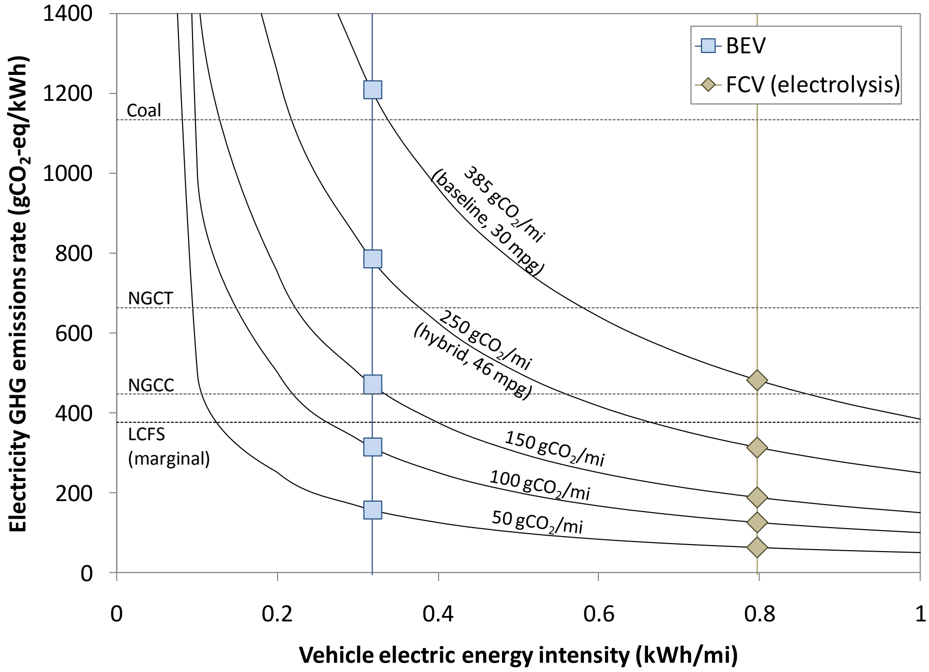

Figure 5: GHG emissions isolines from BEVs and FCVs with hydrogen from electrolysis

GHG emissions perspective, and above which increased all-electric driving is detrimental. For example, if marginal electricity sector emissions are equal to the assumed value in the LCFS (which is unlikely), driving in all-electric mode reduces emissions from vehicles (moving right on the graph along that line leads to isolines with lower vehicle emissions rates). If coal power plants supplies vehicles, increasing all-electric driving leads to increased vehicle emissions (moving right on the graph along the coal line leads to isolines with higher vehicle emissions rates). Based on the assumptions of this analysis, the point at which increased carbon intensity of fuel outweighs improved vehicle efficiency and PHEV emissions increase in all-electric mode occurs when electricity emissions rates equal

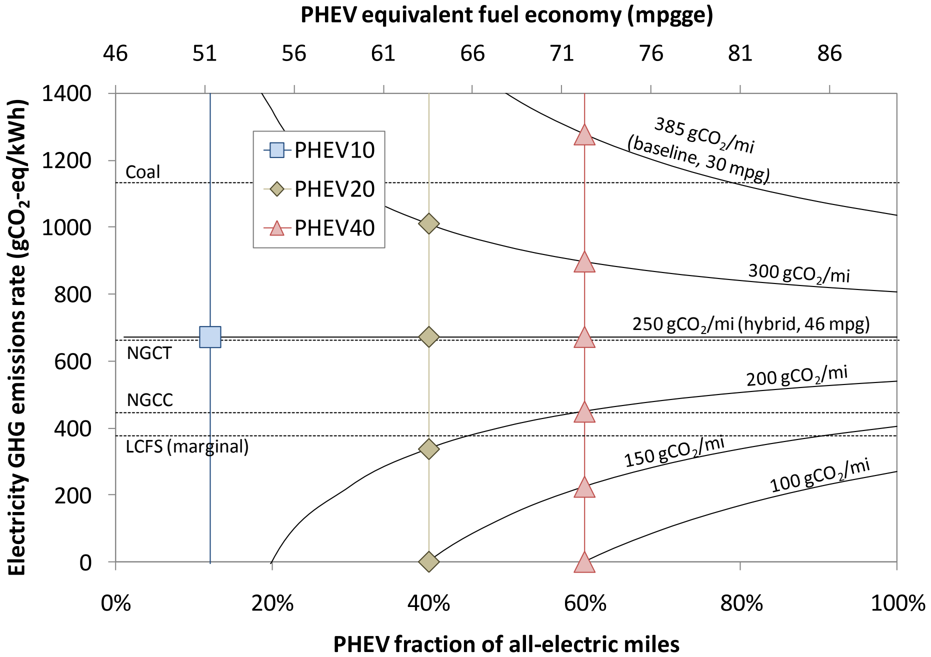

Figure 6: GHG emissions isolines for PHEVs

those from an average NGCT plant in California. This rate is exceeded in only about 2% of hours during a median hydro year.

The impact of electricity supply on PHEV emissions compared to conventional hybrid vehicles is further considered in Figure 7. The figure depicts PHEV emissions based on emissions from the last generator operating in a median hydro year as simulated in CED, as well as emissions from the average and marginal electricity mixes included in the LCFS. As mentioned previously, emissions from the last power plant operating are lower than the emissions rates assumed in the LCFS only during a single hour of a median hydro year. The average marginal emissions rate in CED simulations is 565 gCO_2-eq/kWh, which is 50% higher than the emissions rate from the LCFS marginal mix [21]. It deserves noting, too, that emissions results from CED may well be conservative, as validations of the model underestimated average emissions rates in California.

Compared to the median value of marginal electricity sector GHG emissions as simulated in CED, the LCFS underestimates PHEV emissions by 7 gCO_2-eq/mi for a PHEV10, by 29 gCO_2-eq/kWh for a PHEV20, and by 43 gCO_2-eq/kWh for a PHEV40. Median emissions rates from marginal generation are roughly equal to those at the 25th percentile, so even if PHEVs are only recharged during the six hours of the day in which it is best to do so, similar results hold.

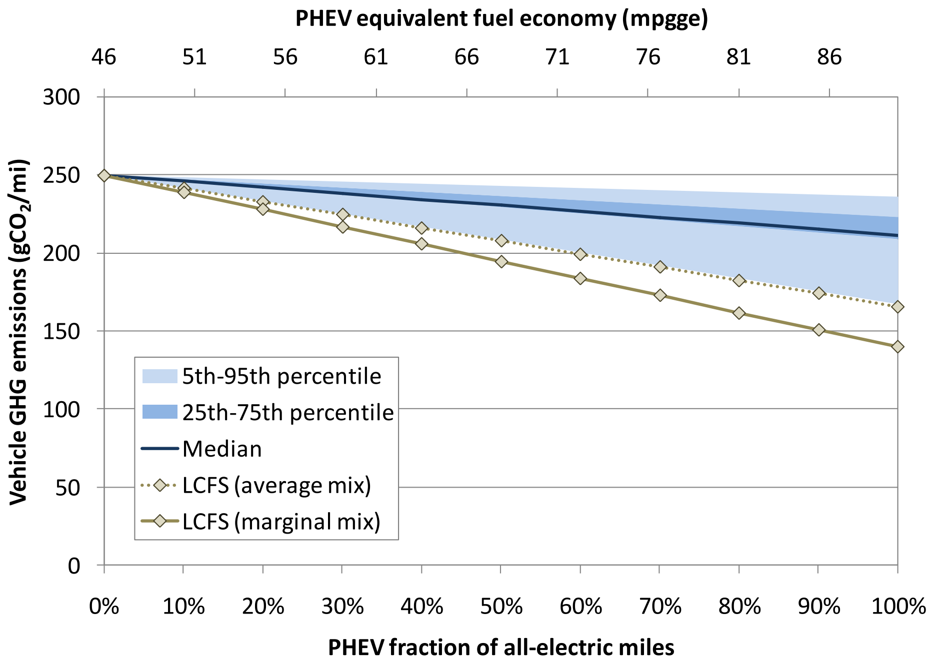

Figure 7: Comparison of vehicle emissions from PHEVs and conventional hybrids

Figure 8 compares vehicle pathway emissions rates based on average last-generator electricity GHG emissions rates by time of day and season. Fuel cells vehicles using hydrogen from electrolysis are off the chart and not shown for clarity. They have a minimum value of 384 gCO_2-eq/mi from 6am-12pm in the winter and a maximum value of 488 gCO_2-eq/mi from 12pm-6pm in the summer. Shown at the right of the figure are vehicle emissions rates obtained using the marginal mix from the LCFS. For reference, emissions from a conventional hybrid are about 250 gCO_2-eq/mi.

On average, all of the vehicles shown (not FCVs with electrolysis) have lower emissions than conventional hybrids throughout the year. Fuel cell vehicles using hydrogen derived from onsite natural gas SMR have the lowest emissions rates most of the year, but BEVs tend to have lower emissions in the winter, when electricity sector emissions are lowest. Vehicles with higher electric energy intensity are more sensitive to marginal emissions from the electricity sector. Emissions rates from BEVs are most sensitive, aside from FCVs with electrolysis, and differ by over 25% between their high if recharged during summer afternoons and their low, if recharged during midmornings of winter months. The marginal mix in the LCFS always underestimates emissions from vehicles. Even if compared only to marginal generation from 12am-6am, the LCFS marginal mix leads to vehicle GHG emissions rates that are 3-30% lower than predicted in the CED model for the PHEV10 case, depending on the proportion of electricity used in the pathway.

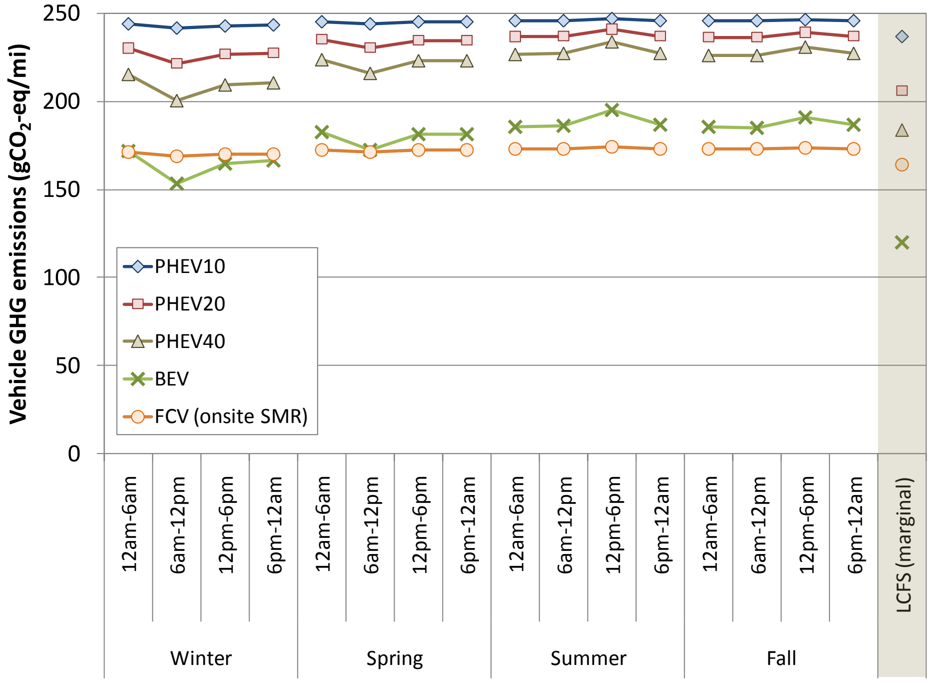

Figure 8: Plug-in vehicle emissions by time of day and season, based on average emissions from the last generator operating (2010, median hydro case)

5 Summary of findings

This paper presents the latest application of the CED model to investigate vehicle and electricity interactions in California. It provides a useful tool for investigating the response of the electricity system to changing demand load profiles, and matches well with how the current system operates. Future work will continue to investigate demand impacts from transportation on California's electricity sector, and will look at long-term impacts of significant penetrations of advanced vehicles on capacity expansion and operation of the California grid. This work will take the form of a scenario analysis, and will consider long-term scenarios for deep GHG reductions in the state.

Specific findings from this initial application include:

- In California, marginal electricity generation has higher GHG emissions rates than average generation,
- Hydro availability affects average emissions much more than marginal emissions,
- On an annual basis, marginal generator emissions are worst from 6pm-7pm, at the end of the evening commute, and remain high until midnight,
- BEVs reduce GHG emissions compared to conventional vehicles even if supplied with coal power; at emissions rates equal to NGCT plants, BEVs are better than hybrids,
- For FCVs with electrolysis to reduce emissions compared to conventional vehicles, electricity emissions must be about equal to those from an average NGCC plant operating in California,
- FCVs using hydrogen from onsite natural gas reforming are less sensitive to electricity sector emissions than more electricity-intensive pathways. They have the lowest emissions of any option considered here on an annual basis and

have a lower GHG emissions rate than BEVs except during winter months and spring mornings, when marginal emissions rates from electricity are relatively low,

- Given the current grid mix in California, PHEVs reduce GHG emissions relative to conventional hybrids except during 2% of hours when marginal generator rates are sufficiently high to negate the efficiency improvement associated with all-electric driving,
- PHEVs essentially break-even with conventional hybrids at an electricity sector emissions rate equivalent to emissions from an average NGCT plant operating in California. Above that rate, driving a PHEV in all-electric mode increases emissions. Below that rate, driving in all-electric mode reduces emissions, and
- Under the assumptions of this analysis, California's Low Carbon Fuel Standard underestimates average marginal electricity emissions by 50% and average vehicle emissions rates by up to 35%.

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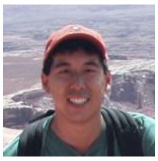

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