Union of Concerned Scientists

Citizens and Scientists for Environmental Solutions

State of Charge: Technical Appendix

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Appendix A: Calculating Emissions from EV Charging

Average vs. Marginal Emissions

There is more than one way to estimate the emissions from charging an EV on the electricity grid, and from using electricity in general. The approach we have chosen, which involves the average emissions intensity of all electricity production in various regions of the country, treats all the electricity produced and consumed in a region equally. That is, no matter how much electricity you use or whether you were using it yesterday or not, your electricity is assumed to be just as clean (or dirty) as anyone else's.

The data we used to estimate regional global warming emissions intensities were based on actual reported power plant emissions for the year 2009. In its Emissions & Generation Resource Integrated Database (eGRID), the U.S. Environmental Protection Agency (EPA) assembled global warming and other emissions data from thousands of power plants operating across the country. The EPA then computed emissions for 26 regions across the entire United States, based on the power plants that supplied electricity to households in those regions.

An alternative approach involves "marginal" emissions. The marginal emissions intensity is estimated by examining what power plants, or types of power plants, are likely to be deployed when new electricity demand is added to the electricity grid above and beyond the demand that already exists. For example, the electricity consumed by an additional load, such as a newly purchased EV or even an extra television set, would have a slightly different emissions intensity from electricity used by an existing light fixture in your home.

The concept of marginal electricity rates is important, especially when evaluating how electricity demand from thousands or millions of new EVs added to the grid over the coming decades will be met. If the new generation needed to meet EV charging demand is composed of renewables or other sources of generation that are cleaner than existing power plants, then the net impact of EVs will be to lower the grid's emissions intensity. If new plants are built that have higher emissions rates than today's average, the net impact of increased EV demand will be to increase emissions intensity. This fact has inspired a variety of analyses, using marginal emissions approaches, to evaluate the potential impact of increasing amounts of EV charging on future emissions of the electricity grid (ANL 2010; ORNL 2008b; EPRI and NRDC 2007a; NREL 2007).

While a marginal emissions analysis of EV charging is important for forward-looking studies of the policy implications of large-scale EV adoption, our goal in this analysis is to give consumers an idea of what the typical global warming emissions of the electricity used to charge their EV will be on today's electricity grid. Therefore we use the average emissions intensity of the electricity, essentially treating all electricity on the grid at a given time as a shared resource, or pool of electrons, available to all electricity consumers. This approach ignores the impact of any changes in electricity production that may be caused by a single individual plugging in an EV—an impact that is virtually imperceptible.[1]

Regional Emissions Estimates: Data Sources and Calculations

The greenhouse gas (GHG) emissions we attribute to driving an electric vehicle are those that result from the production of electricity needed to charge the vehicle. We factor in emissions created by power plants when generating the electricity, and also emissions that result from obtaining and transporting the fuel used in these plants.

Power Plant Emissions

The emissions produced by electricity generation for EV charging come from the aforementioned eGRID database, which is a comprehensive source of emissions data for every power plant in the United States that generates electricity for the grid and that provides its data to the government (EPA 2010c). We used to the most up-to-date version of eGRID possible, eGRID 2012 v1.0, which contains plant emissions and generation data from the year 2009 and subregion organization from the year 2012 (EPA 2012b). The GHG emissions rate for electricity generation for each of the 26 regions analyzed in the report comes from the *eGRID2012 Version 1.0 Subregion File (Year 2009 Data)* (EPA 2012a).

The subregions are groups of plants organized by the EPA based on Power Control Areas (PCAs) and North American Reliability (NERC) regions (EPA 2010c). These groupings, which are meant to reflect which power plants serve which households, reasonably approximate the grid mix of electricity used by those households. The level of disaggregation of the eGRID subregions allows for more precise calculation of plant GHG intensities than a national average, as regional variations in grid mix are taken into account. For this reason, eGRID was chosen over other data sources that had the same detailed plant information but fewer subregions. The actual grid mix of a household's electricity is specific to the individual utilities serving each household, but specific grid-mix data are not readily available for most utilities and therefore were not used in the study.

[1] An individual EV driven 30 miles per day will consume about 300 kWh per month. This is the equivalent of adding less than half a household's worth of electricity consumption to a regional grid with millions of homes (based on EIA data on average household electricity consumption).

eGRID's methodology treats the subregions as closed systems, calculating the emissions intensity of generation for each one based on the emissions intensities of the plants it contains. This methodology ignores imports and exports of electricity between subregions, which harms the accuracy of the regional emissions estimates. Further disaggregation of these subregions would increase the precision of the emissions estimates, but would exacerbate the loss of accuracy due to the omission of imports and exports. Therefore, the 26 eGRID subregions are recommended by the eGRID's designers as the level of disaggregation best suited for GHG emissions estimates of electricity use, as they achieve the best balance between the precision gained by disaggregation and the accuracy lost by omitting imports and exports (EPA 2009).

Transmission Loss Factors

The eGRID emissions rates do not account for transmission and distribution losses between the power plant and the household. To account for these losses, so we could calculate emissions per unit of energy used (rather than energy produced), we followed eGRID's recommendation (EPA 2010c) to increase the emissions rates using grid loss factors found in the file *eGRID2012 Version 1.0 Grid Gross Loss (Year 2009 Data)* (EPA 2012a), shown in Table A.2. There are five grid loss factors that vary by regions called interconnect power grids, and each state is given a grid loss factor based on the interconnect power grid it belongs to in the file *eGRID2010 Version 1.1 State Import-Export File (Year 2007 Data)* (EPA 2010a). Although eGRID subregions are based on utility service territories that do not coincide with state boundaries, we assigned each subregion one of these factors based on those of the states. The purpose of doing this was to avoid having multiple emissions rates for a single subregion that serves two or more states with different grid loss factors. The determination of which state grid loss factors were assigned to a subregion was based on a rough representational map of approximate subregion boundaries superimposed over state boundaries.[2] For subregions that encompass parts of multiple states with different grid loss factors, the most prevalent grid loss factor—based on geographic area of the portions of the states comprising the subregion—was used.

Upstream Emissions Factors

The eGRID subregion emissions rates include only those emissions produced at the plant generating the electricity, and they exclude upstream emissions resulting from the mining and transport of the power plant feedstock (EPA 2010c). Therefore we calculated a feedstock emissions rate for each subregion;

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[2] This map is found in *The Emissions & Generation Resource Integrated Database for 2010 (eGRID2010) Technical Support Document*. Online at *www.epa.gov/cleanenergy/documents/egridzips/eGRID2010TechnicalSupportDocument.pdf*.

this rate depends on which fuel types the corresponding power plants use. Each fuel type has a unique upstream emissions rate, which we obtained from a life-cycle emissions model, called GREET, developed by Argonne National Laboratory.[3] The percentage of generation from each fuel type in a subregion was then obtained from the *eGRID2012 Version 1.0 Subregion File (Year 2009 Data)* (EPA 2012a).

For each subregion, the fuel-type emissions rates are multiplied by the share of generation they represent in that subregion; the sum of these products is the subregion's feedstock emissions rate. Most fuel types in GREET correspond directly to a fuel type in eGRID, but there were a few exceptions. A very small share of generation in eGRID subregions corresponds to a fuel type labeled "generic fossil;" for this fuel type, the emissions rate from GREET for natural gas was chosen as a conservative guess since its value is higher than those of coal and oil (the other two fossil fuels with known feedstock emissions rates in GREET). An even smaller share of generation in eGRID subregions comes from unknown sources; for this category of fuel type, the feedstock emissions rate (which varies for each region) is the generation-weighted average of the upstream emissions rates for the other fuel types.

GREET has already built a uniform grid loss factor into these feedstock emissions rates. But to keep the loss factors consistent with the power plant emissions rates, we back this factor out of the feedstock emissions rates. We then apply the same loss factor from eGRID used for power plant emissions rates to each subregion's feedstock emissions rate.

Total GHG Emissions Rate of EV Charging

The total GHG emissions rate of EV charging for eGRID subregions was computed by summing the grid-loss-adjusted power plant emissions rates for each subregion with the corresponding grid-loss-adjusted feedstock emissions rate.

Determining Which Subregion Each City Is In

Each city analyzed in the report is mapped to one eGRID subregion and is assigned the GHG emissions rate of charging for that subregion. The cities are assigned to the subregions using the EPA's Power Profiler Zip Code Tool v3-1. The Power Profiler identifies the electric utilities, each of which belong to a specific subregion, that serve a zip code, then maps subregions to zip codes accordingly.[4] A separate zip code database was used to determine all the zip

[3] GREET v1_2011 was used; Feedstock emissions factors come from Table 9: Fuel-Cycle Energy Use and Emissions of Electric Generation: Btu or Grams per mmBtu of Electricity Available at User Sites (wall outlets) in the Electricity tab.
[4] From the TOC tab of Power Profiler Zipcode Tool.

codes served by a city; these zip codes were then input to the Power Profiler so the corresponding eGRID subregions could be displayed.

In the large majority of cases, all zip codes are served by utilities that belong to the same subregion. In these cases it was straightforward to assign the city to that eGRID subregion. In a few cities (Jacksonville, El Paso, and Louisville), all zip codes are served by a primary utility belonging to the same subregion, but some of the minor utilities belong to a different subregion. In these cases only the subregion served by the primary utility was used, so that only one subregion was mapped to that city. In a few other cities (Memphis, District of Columbia, Kansas City, and Mesa), the predominant utility in some zip codes belongs to one subregion, while the predominant utility in other zip codes belongs to a different subregion. In these cases the predominant utility for the entire city was chosen, and whichever subregion it belongs to was mapped to that city.

GHG Emissions Rate Assumptions and Results by Subregion

The regional grid mix and estimated emissions intensity for all eGRID subregions, with adjustments for upstream emissions and grid losses, are shown in Tables A.1 and A.2.

Table A.1. Grid Mix By Region

Grid Region Acronym	Name	% Coal	% Natural Gas	% Nuclear	% Biomass	% Hydro	% Wind, Solar, Geothermal	% Other Fossil	Emissions Intensity (gCO_2e/kWh)
AKGD	ASCC Alaska Grid	12	66	0	0	8	0	14	748
AKMS	ASCC Miscellaneous	0	4	0	0	64	1	31	300
ERCT	ERCOT All	33	48	12	0	0	5	1	685
FRCC	FRCC All	24	55	14	2	0	0	5	680
HIMS	HICC Miscellaneous	2	0	0	3	4	14	77	778
HIOA	HICC Oahu	18	0	0	2	0	0	80	910
MROE	MRO East	69	5	15	3	3	2	2	825
MROW	MRO West	69	2	14	1	4	9	0	835
NYLI	NPCC Long Island	0	77	0	5	0	0	18	801
NEWE	NPCC New England	12	42	30	6	7	0	3	439
NYCW	NPCC NYC/Westchester	0	56	41	1	0	0	2	393
NYUP	NPCC Upstate NY	14	19	31	2	31	2	1	286
RFCE	RFC East	35	17	43	1	1	0	2	516
RFCM	RFC Michigan	72	10	15	2	0	0	1	865
RFCW	RFC West	70	4	24	1	1	1	1	787
SRMW	SERC Midwest	80	1	17	0	2	0	0	898
SRMV	SERC Mississippi Valley	23	45	26	2	2	0	2	577
SRSO	SERC South	52	22	18	3	4	0	0	712
SRTV	SERC Tennessee Valley	59	9	22	1	9	0	1	710
SRVC	SERC Virginia/Carolina	45	9	41	2	2	0	1	550
SPNO	SPP North	74	8	13	0	0	4	0	936
SPSO	SPP South	55	34	0	1	6	4	0	860
CAMX	WECC California	7	53	15	3	13	7	2	423
NWPP	WECC Northwest	30	15	2	1	47	4	0	451
RMPA	WECC Rockies	68	23	0	0	4	5	0	983
AZNM	WECC Southwest	39	36	16	0	6	3	0	675

Source: EPA 2012a.

Table A.2. EV Charging Emissions Rates by Region

eGrid Subregion Acronym	Emissions from Power Plants (gCO_2e/kWh)	Transmission Loss Multiplier	Emissions from Power Plants after Transmission Loss (gCO_2e/kWh)	Upstream Emissions after Transmission Loss[a] (gCO_2e/kWh)	2007 EV Charging Global Warming Emissions Rate (gCO2e/kWh)
AKGD	582	1.06	618	129	748
AKMS	237	1.06	252	48	300
ERCT	538	1.09	585	101	685
FRCC	536	1.06	569	111	680
HIMS	616	1.08	668	110	778
HIOA	727	1.08	788	121	910
MROE	726	1.06	771	55	825
MROW	743	1.06	789	47	835
NYLI	614	1.06	652	149	801
NEWE	333	1.06	354	85	439
NYCW	278	1.06	295	98	393
NYUP	227	1.06	241	46	286
RFCE	432	1.06	459	57	516
RFCM	757	1.06	804	61	865
RFCW	693	1.06	736	51	787
SRMW	798	1.06	847	50	898
SRMV	456	1.06	484	93	577
SRSO	604	1.06	642	70	712
SRTV	619	1.06	657	53	710
SRVC	472	1.06	502	49	550
SPNO	828	1.06	879	57	936
SPSO	728	1.06	773	86	860
CAMX	300	1.09	327	96	423
NWPP	373	1.09	407	44	451
RMPA	831	1.09	906	77	983
AZNM	543	1.09	591	83	675

Note: (a) Upstream emissions are those associated with the extraction and transportation of feedstocks for electricity generation.

Hourly Emissions Estimates: Dispatch Modeling with ORCED

UCS used a modified version of the Oak Ridge Competitive Electricity Dispatch Model to determine the emissions intensity of regional electricity generation on an hourly basis.

Estimation of Average Hourly Emissions

A modified version of the Oak Ridge Competitive Electricity Dispatch Model (ORCED), developed by Stanton Hadley at Oak Ridge National Laboratory, was used to determine the emissions intensity in 2010 of regional electricity generation in the United States on an hourly basis. Unlike the EPA's eGRID2012 Version 1.0 database,[5] which only reports how much electricity each power plant generates over the course of the year, our modified version of the ORCED model estimates the mix of power plants generating electricity at any given hour of the year. Like the eGRID database, the ORCED model makes use of subregions, each of which represents a network of power plants dedicated to meeting the electricity demand of a specific group of customers. The ORCED model, which uses a greater level of aggregation than the eGRID database, contains 13 regions that correspond to electricity-market module regions found in versions of the *Annual Energy Outlook* released before 2011. A different hourly grid mix is determined for each of the 13 subregions.

Below is a description of how the model was utilized and updated for this analysis. For a more in-depth presentation on the ORCED model, see *The Oak Ridge Competitive Electricity Dispatch (ORCED) Model*, online at *apps.ornl.gov/~pts/prod/pubs/ldoc9472_orced_modelfinal.pdf*.

ORCED Facilitates the Determination of an Hourly Grid Mix

The hourly estimate of the mix of generating units is made possible by an algorithm in the ORCED model that estimates the likely order in which utilities in each region will dispatch power plants to meet incremental increases in electricity demand. The dispatch order for each region is fixed throughout the year, but the level of demand at any given time, along with how much electricity each plant can produce, will determine how many plants need to be run. When electricity demand is high, more plants are running than when electricity demand is low; therefore the grid mix will be slightly different for different levels of demand. The grid mix at any given hour can therefore be estimated as long as one knows the demand at that hour; plants will be "turned on" sequentially following the dispatch order until the demand is met.

[5] See *www.epa.gov/cleanenergy/energy-resources/egrid/index.html*.

ORCED Was Modified to Display the Hourly Grid Mix

The original ORCED model was not equipped with the capability to output the average emissions rate of the grid at a certain hour; instead, it generates output representative of an entire year. Nonetheless, the yearly results are based on predicted mixes of power plants based on a distribution of hourly demand levels built into the model. The ORCED model does not explicitly display the relationship between hourly demand and the mix of power plants that run. Instead, ORCED displays for each plant the percentage of time during the year that demand is high enough to require that plant be run. These percentages vary for summer, winter, and off-peak seasons,[6] so they are displayed separately for each season. An exception exists for hydro power plants, as discussed below. ORCED also displays the percentage of time during the year that each level of demand is seen in each region for each season.

Using the aforementioned data, we were able to modify the model to link each power plant to the minimum level of demand in each season that would require the plant be run. Given that the demand level and season at every hour of the year in a region is built into the ORCED model, we added additional code in order to link each hour to the plants that would need to be run that hour, based on demand and season. Once complete, the modified version of the ORCED model was able to display the mix of all non-hydro plants running at every hour of the year in each region.

Hydro power plants are modeled by ORCED to generate power as a function of demand. As demand in a region increases, hydro plants in that region generate more power. For each season in each region, ORCED displays the different levels of hydro power possible and the percentage of time during the year that demand is high enough to result in each level of production. Because a procedure for linking these percentages to hours of the year was already established for the other types of plants, we added code to the model so that this same procedure could be applied to hydro power.

Our calculations do not include the impacts of intermittent and random outages on hourly grid mixes, yet such outages are incorporated into the model when it is run in its unmodified state. Stanton Hadley (ORCED's creator), however, assured us that the accuracy of our results was not significantly affected by our omission.

Plants Were Linked to Emissions Data in ORCED to Determine CO_2 Intensity

Once the mix of plants running at each hour of the year was determined, plant emissions data were used to compute the weighted-average CO_2 intensity of

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[6] This is because plant capacity factors are different for each season. Fewer plants are needed when capacity factors are higher, and vice versa. Within each season, we assume that plants are run at a constant level.

power generation in each region at each hour. Once the emissions intensities of electricity generation were computed, the emissions rates were aggregated over the year, keeping each hour separate so a yearly-average emissions rate for each hour of the day could be obtained. This procedure was performed for each of the 13 regions analyzed in the ORCED model.

Updates Made to Data in the Model

Because exogenous data used in the ORCED model were from 2007, we updated much of these data using more recent sources. Data on regional electricity demand, power plant feedstock prices,[7] and the prices of SO_2 and NO_x allowances (all of which came from the 2007 version of the *Annual Energy Outlook*) were replaced with calendar year 2010 data from AEO 2010.

The version of the ORCED model available for download contained power plant data used for a year 2020 simulation, which means these data include power plants expected to be built between 2010 and 2020 and omit power plants expected to be retired between those same years. Because our analysis was for the year 2010, we needed to remove any power plants built after 2010 from the plant inventory, and we also needed to add power plants scheduled for retirement between 2010 and 2020. Deleting plants built after 2010 was straightforward, but power plant data from a 2010 National Energy Modeling System input file were needed to identify and replace those plants scheduled for retirement between 2010 and 2020 that had been removed from the original ORCED model.

Aside from the changes noted in the paragraph above, the power plant data were not updated from the year 2007. We estimated that the impact of updating the remaining plants with 2010 data would have been minimal.

Hourly Emissions Results

Table A.3 shows the estimated average hourly emissions intensity for each ORCED region. The emissions intensities are displayed in grams of CO_2 per kilowatt-hour of electricity generated, and are color-coded on a scale that shifts from dark green to dark red as the CO_2 intensity of electricity generation increases. In general, most regions have slightly higher average emissions intensities during non-peak hours. The reasons for this vary by region. In areas such as California, which have a high percentage of hydro sources, evening emissions intensities can be higher because dams are controlled to generate more power during peak demand (i.e., daytime) and less at night. In many areas where coal-fired power plants provide a significant fraction of electricity needs,

[7] The price for biomass actually came from the 2009 version of the National Energy Modeling System, as this price was not included in the 2009 or 2010 versions of the *Annual Energy Outlook*.

the grid's emissions intensity decreases when cleaner natural gas plants are ramped up to meet peak demand during the day.

Table A.3. Hourly Average Global Warming Emissions Intensity for 13 ORCED Regions

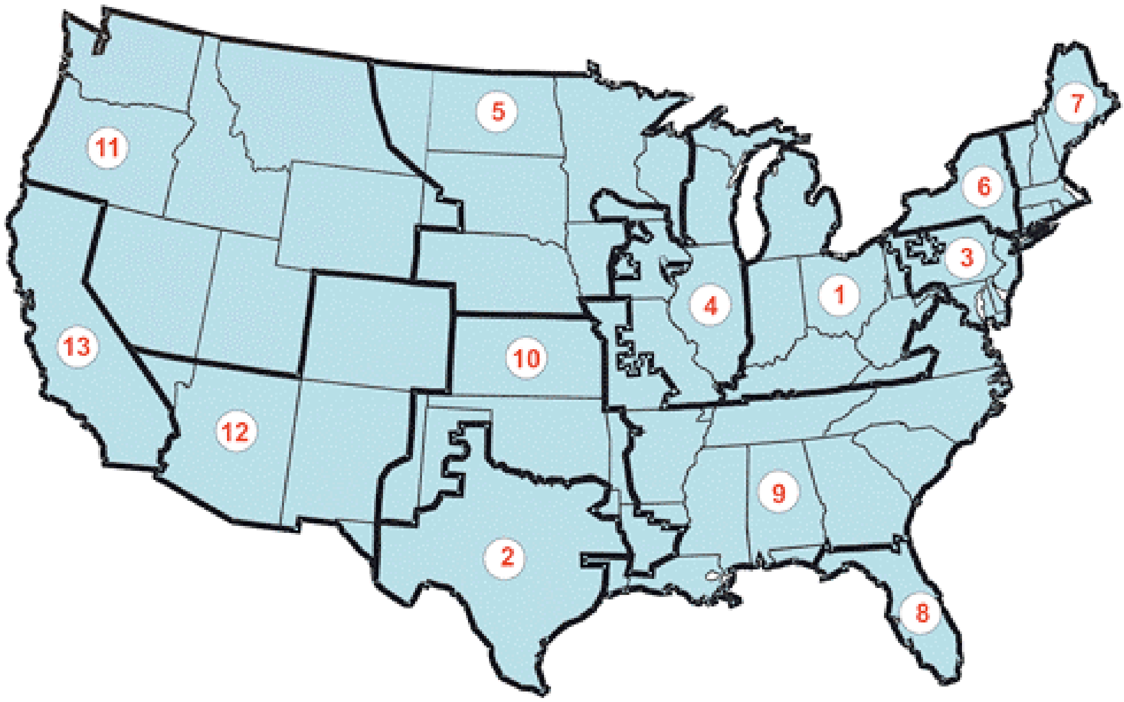
Legend

Emissions Rate: (gCO_2/kWh)	Minimum 278				Maximum 929

Hour	Region 1	2	3	4	5	6	7	8	9	10	11	12	13
1	876	671	520	591	831	329	394	655	638	913	475	839	377
2	873	679	508	582	828	341	393	667	634	923	487	846	378
3	871	684	499	576	824	348	392	675	632	929	492	849	378
4	868	687	496	574	819	350	392	679	631	927	488	848	376
5	870	683	499	578	825	351	393	679	630	928	481	848	378
6	873	676	513	588	829	340	393	669	630	919	456	838	378
7	876	665	530	601	819	319	390	651	625	899	424	821	368
8	877	660	537	606	799	301	381	640	624	883	404	805	349
9	878	655	542	610	793	291	376	632	623	874	395	792	335
10	878	649	545	612	789	284	373	626	619	865	392	781	322
11	878	645	546	613	784	281	370	621	615	858	392	770	311
12	878	643	546	613	783	280	370	620	612	854	393	764	307
13	878	642	545	613	786	279	371	619	611	852	396	760	307
14	878	642	545	613	787	279	371	619	609	850	399	757	306
15	878	642	544	612	789	280	373	620	609	850	401	755	307
16	879	642	544	613	791	280	373	620	607	850	401	753	309
17	879	642	545	614	787	279	369	620	605	848	396	748	308
18	879	640	545	615	780	279	366	619	601	843	389	737	299
19	878	639	545	615	776	279	366	617	599	838	386	731	294
20	878	639	546	615	778	279	366	618	601	839	386	732	293
21	878	639	546	615	781	278	367	618	608	844	389	743	295
22	880	642	547	614	794	279	376	621	622	856	401	769	312
23	881	648	548	612	821	288	390	628	637	877	425	805	343
24	880	660	536	602	833	307	395	640	642	898	453	827	369

Each numbered region above corresponds to the same-numbered ORCED region on the following page:

Figure A.1. Map of ORCED Regions



Source: ORNL 2008b.

Appendix B: Calculating the Cost of EV Charging

Collecting Electricity Rate Data

The cost of electricity for home EV charging in each of the cities in our analysis was estimated from electricity rate data gathered from utilities.

How Utilities Were Chosen

The cost analysis for this report focuses on 50 cities, chosen because they were the largest in the United States as measured by city-proper population. In cities with regulated electricity markets, the analysis includes every utility available to the inhabitants of those cities. In cities with deregulated electricity markets, the main delivery providers are included and are assumed to provide electricity only from their default supplier(s). Therefore, some electricity suppliers serving deregulated markets are not included in the analysis. In addition, when information on a delivery provider's default supplier could not be found, the delivery provider was omitted from the analysis.

How Data Were Collected

Utility rate data were collected by the consulting firm TIAX LLC, with almost all the information coming from publicly available rate sheets posted on utility websites. When the data available online proved to be insufficient, additional information was gathered through phone and email correspondence with utilities. These data were compiled over the period from March 2011 to January 2012. Some of the rate plans included in this report have been updated by utilities since the data were initially gathered, and many of these changes were incorporated into the analysis between September 2011 and January 2012. There is still the possibility, however, that the rate data from some utilities have undergone changes that are not included in this analysis.

Treatment of Zones within Utility Service Territories

The territories of Con Edison, LADWP, and SDG&E, which encompass New York City, Los Angeles, and San Diego, respectively, are divided into zones. One component of Con Edison's electricity rates varies by zone, while LADWP's and SDG&E's baseline quantities—the amounts of electricity consumption available at the cheapest tier—vary by zone as well. For each city, the rate information from the utility's zone that corresponded most directly to the city proper was chosen. This was Con Edison Zone J for New York City, LADWP Zone 1 for Los Angeles, and SDG&E Inland Zone for San Diego.

PG&E's service territory (which includes the cities of San Jose, San Francisco, Fresno, and Oakland) is also divided into zones as well. As is the case with SDG&E and LADWP, baseline quantities vary by PG&E's zones, so we used the zone-appropriate baseline quantities for each city. San Jose is located in Zone X, San Francisco and Oakland are located in Zone T, and Fresno is located in Zone R.

Types of Information Gathered

Utility Rate Data

For the utilities included in the analysis, information was gathered about every residential rate plan under which a household can charge an electric vehicle. If language in a plan's rate sheet suggested that EV charging would not be allowed, that rate plan was omitted from consideration. Separate rates or baseline quantities for customers with electric heating, which are offered by some utilities, were not included in the analysis. Customers with electric heat should check with their utilities for rates if they charge their EVs on the same plan as their household, given that the rates and tier structures for such customers are often different.

All data necessary to assess the cost to a household of charging an EV were collected. These data were of two types: (1) costs that depend on how much energy is used in a month (consumption), and (2) costs that depend on the peak amount of energy used in a given instant (demand).

For the first component, all costs imposed per kilowatt-hour of electricity used—which include items such as energy charges, fuel adjustment factors, and transmission charges—were summed to develop one single marginal rate in cents per kilowatt-hour. The marginal rate indicates how much money the consumer pays for each additional kilowatt-hour used to charge an EV; the total consumption cost of EV charging over a period of time can therefore be found by multiplying this rate by the number of kilowatt-hours used for EV charging during that time. Fixed costs, such as a five-dollar monthly service fee, are omitted because the household would be paying them regardless of whether or not they charge an EV.

The second component, which was found only in three rates included in the analysis, consists of a monthly charge imposed per kilowatt of peak electricity demand. The more electricity a customer uses at once, the higher this cost will be. Therefore the contribution of EV charging to demand costs is found by multiplying the demand cost by the power drawn to charge an EV. This procedure is straightforward for rate plans in which an EV is metered by itself, as the vehicle is the only load drawing power. For rates in which a household and EV are billed together on a single meter, however, this approach assumes that the household's peak demand is the sum of EV charging demand and peak demand from the rest of the household. This assumption is only true if at some time during a given month, EV charging coincides with the peak demand from the household's other appliances. Therefore the assumption represents the worst-case scenario, providing the maximum demand charge possible due to EV charging. In practice, the demand charge may be less if EV charging never coincides with a household's peak demand for other appliances over the course of a month, and in extreme cases the demand charge may be zero if EVs are charged exclusively during off-peak times and never contribute to a household's peak demand.

Tax and Franchise Fees

For each utility, we gathered information on any taxes or franchise fees (monies paid to municipalities for the right to operate locally) not already factored into the utility's electricity rates. This information came from sample utility bills, government websites, and phone conversations with utility customer-service representatives. These taxes (which can occur at the state, local, or county level) or franchise fees (which increase the marginal cost of electricity for the utility's customers) were factored into our rate calculations to determine the actual cost one would pay for electricity.

Amount of Electricity Used for EV Charging

Consumption

For the sake of simplicity, we assume every EV owner drives his or her EV the same number of miles each day. In this analysis we use 30 miles of daily driving for each EV, based on the average daily mileage per vehicle[8] determined by the 2009 National Household Transportation Survey. We also assume each mile driven in an EV requires 0.34 kWh of electricity from the outlet, based on the 0.34 kWh/mile plug-to-wheel efficiency of the first-generation Nissan LEAF, which is the most prevalent plug-in EV on the road today. Other such EVs have slightly different electric-drive efficiencies and therefore may require more or less electricity to operate, but the efficiencies of the Tesla Roadster and Chevy Volt, two other well-known EVs, are very similar to that of the LEAF. Thus our analysis assumes that 10.2 kWh (30 miles x 0.34 kWh/mile) of electricity are used to charge every EV each day of the year. We assume all EV charging is done at home, where the majority of EV charging is likely to occur. Any charging done at the workplace or other locations would lower household energy consumption.

Capacity

In this analysis, we assume all EV charging is done at 3.3 kW, which is the power level for a Level 2 charge using the onboard chargers of both the LEAF and Volt.

[8] The actual number is 31.1 miles per vehicle.

EV owners also have the option of using a Level 1 charge, which only draws 1.4 kW but takes more than twice as long. When charging on one of the few utility rates that include demand costs, Level 1 charging might be cheaper because of its lower power level.

Handling of Electricity Rate Data

Tiered Rates

For many utility rates, the consumption component of the costs has a tiered structure—costs vary according to how much electricity is used. A certain number of kilowatt-hours are allocated to each tier, and once those kilowatt-hours are used the consumer moves into the next tier. When an EV is metered separately from the rest of the household, calculating EV charging consumption costs on a tiered rate plan is straightforward; the cost per kilowatt-hour is the average of the tiered rates, weighted by the amount of electricity consumed in each tier. When a household and EV are billed together on a single meter, however, a slightly different methodology must be used. Each month's EV charging consumption is treated as the "last" electricity used by the household that month, regardless of when the charging actually took place. The result is that EV charging will incur the highest-tiered electricity rates paid by the household each month. An estimate of monthly home (non-EV) electricity consumption is used to determine the specific tier(s) in which EV charging occurs.

For most cities, this estimate comes from state-based data on average monthly residential electricity consumption, available from the U.S. Energy Information Administration.[9] By using average electricity consumption, we assume all households in a given state use the same amount of energy. Customers who use less electricity than average will therefore usually pay a lower rate to charge their EVs on tiered single-meter rates than our analysis shows, and customers who use more electricity than average will probably pay a higher rate. But in some cities, where electricity rates become lower with higher monthly consumption, this trend is actually reversed.

Using monthly average electricity consumption also assumes household energy consumption is the same for each month. But because of seasonal variations in energy consumption, these estimates of household consumption may be too high for some months and too low for others. Such variations may not cancel out—sometimes only one season is tiered, and sometimes the seasons have

[9] See Table 5: Residential Average Monthly Bill by Census Division and State, online at *www.eia.gov/cneaf/electricity/esr/table5.html.*

different baselines that don't directly reflect the differences in seasonal consumption.

The seasonal variation in monthly residential energy consumption is largely due to the fact that household electricity consumption is strongly related to climate. Therefore estimating a city's electricity consumption on the basis of state data assumes a relatively homogenous climate exists across all of the state's populous areas. This assumption is reasonable for many states throughout the country. However, it does not hold up well for California given the wide array of diverse climate zones found among the state's major cities (Figure B.1).

Figure B.1. Climate Differences among and within the United States

Source: GeoNova 2011.

Therefore different methodologies were used for cities in California. For those served by PG&E, SDG&E, and SCE, the average energy consumption of households was estimated on the basis of a California Public Utilities Commission (CPUC) requirement that these utilities set their baseline quantities to between 50 and 60 percent of the average household consumption of their customers.[10] PG&E claims on its website that it sets its baseline levels using the highest end of this range, so we computed our estimate of the average household energy consumption for each city served by PG&E (San Jose, San Francisco, Fresno, and Oakland) as 167 percent (the inverse of 60 percent) of the PG&E baseline quantities for that city.

We did not come across similar claims from SDG&E and SCE, so the median of the CPUC's range was used to estimate the average household consumption in cities served by these utilities. The estimated average household consumption for Long Beach was computed as 182 percent (the inverse of 55 percent) of SCE's baseline quantities, and the estimated average household consumption for San Diego is computed as 182 percent of SDG&E's baseline quantities. We were unable to ascertain a relationship between the baseline values and electricity consumption for California cities served by SMUD and LADWP, so we contacted these utilities to learn the average yearly electricity consumption of their customers. The yearly average was then divided by 12 to compute a monthly estimate of the average household energy consumption in those locales.

Rate Variation

Our analysis estimates the cost of EV charging on a given rate plan over the course of an entire year; to do so we calculate one single electricity rate representative of that whole year of charging. In reality, utility rates often vary by season, month, day, and even hour. By assuming the same amount of EV charging each day, we are able to address most temporal variations on rate; we take averages of the varied rates weighted by the amount of time to which each rate applies.

Seasonal and Daily Variations

Seasonal rates are weighted and averaged based on the fraction of the year each season comprises. For example, if summer and winter each spanned six months they would contribute equally to the yearly rate. Monthly and daily rate variations are addressed in the same way. For example, weekend days often differ from weekdays because their peak hours are different or nonexistent. In these cases, the weekly average rate is found by weighting the weekday rate by five-sevenths and the weekend rate by two-sevenths.

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[10] An unintended advantage of using this methodology for these PG&E cities is that the known relationship between baseline values and electricity consumption allows the estimates of household electricity usage to track seasonal variations in the baseline values. Many of the cities in our analysis have separate baseline values for summer and winter, but only the cities to which this methodology is applied have distinct estimates of household consumption for these seasons as well.

Time-of-Use Variations

When charging an EV under a time-of-use plan, in which electricity rates vary by hour, we assume more charging will occur at some hours than at others. Therefore the rates at the most common hours for charging will factor more into the calculation of charging costs than the rates during hours when less charging occurs.

We assume EV drivers on time-of-use plans will try to maximize the amount of charging they are able to do during off-peak times. Because off-peak hours vary among different utilities, we did not attempt to assign a share of charging time to any particular hours of the day. Instead, we assume 70 percent of charging is always done at off-peak rates over the course of a year, whatever those hours may be—reflecting the idea that 70 percent of charging demand can be flexible enough to be done at optimal times. We then assume the other 30 percent of charging occurs at random times, based on need, and therefore the rate at each hour of the day contributes an equal share to this 30 percent of charging costs. This scheme allows our charging profile to reflect a preference for off-peak charging, while making sure that all components of the time-of-use rate are factored into the charging-cost calculation.

Off-peak times under TOU plans comprise anywhere from 5 to 19 hours of the day, depending on the utility, so when combined with the 70 percent of charging we assume always occurs at off-peak times, 76 to 94 percent of the charging under a given utility's TOU plan will incur off-peak rates. These figures are consistent with what a charging profile developed by the Electric Power Research Institute and the Natural Resources Defense Council (EPRI and NRDC 2007a) would indicate for the share of off-peak charging, if one was to redistribute the public/workplace charging (which is not pertinent to residential charging) proportionally among the other hours. The figures are also supported by preliminary data from an SDG&E rate study, which found that for 360 customers with EVs on separately metered TOU rates, 84 percent of their charging was done at the lowest off-peak rates (Haddow 2012). Although an individual's EV charging will likely vary from day to day, we assume this charging will fit our distribution over the course of a year.

To determine the cost of charging an EV on a TOU rate, we compute a single average electricity rate by multiplying the off-peak TOU rate by 70 percent, multiplying the rate at each hour of the day both by one-twenty-fourth (that hour's fraction of the day) and 30 percent, then summing the resulting 25 products. It is important to remember that our charging profile is just an estimate; EV owners can save more than what we calculate by always charging at off-peak times, (or save less if they frequently have to charge during the day).

Fuel-Price Variations

Another type of monthly rate variation that occurs in some utility rate plans is marginal cost, based on the changing price of the fuel that power plants use to produce electricity. These marginal rates are calculated for each month's electricity bill, as they are not predictable. To reduce the uncertainty associated with these costs, utilities publish historic monthly rates, which help give the customer an idea of what the rate might be for upcoming months. For our analysis, we take the average monthly marginal cost over the most recent year and treat it as a single (constant) rate that will apply to the upcoming year.

Residential Rates Omitted from the Analysis

Many residential rates offered by utilities in our analysis were excluded, even though one could charge an EV on them:

- TOU rates were sometimes excluded (PG&E's, for example) when the same utility offered a similar EV rate that was clearly cheaper at all times of the day.
- TOU rates with capacity charges were always excluded when the same utility offered a TOU rate without demand charges. This was done because capacity charges incurred from EV charging are difficult to estimate, and also because TOU rates with capacity charges are generally unfavorable for fueling an EV, given the high power draw of Level 2 charging.
- TOU rates with "surprise" peak times set at the discretion of the utility were also excluded. The peak times for such rates are not posted in advance; instead, the utility warns customers shortly before the peak goes into effect, often with lead times as short as 30 minutes. Because it is impossible to predict how much EV charging will cost without knowing when the peak hours are, we did not feel it was useful to include these rates.

Results of Charging-Cost Calculations

Table B.1. Standard Residential Rate Plan

City	Utility	Charging Cost (cents/kWh)
Albuquerque	Public Service Company of New Mexico	14.0
Arlington	TXU Energy	11.1
Atlanta	Georgia Power	11.2
Austin	Austin Energy	10.6
Baltimore	Baltimore Gas and Electric Company	10.7
Boston	NSTAR	15.4
Charlotte	Duke Energy	8.9
Chicago	ComEd	11.6
Cleveland	Cleveland Public Power	11.7
Cleveland	First Energy—The Illuminating Company	7.5
Colorado Springs	Colorado Springs Utilities	9.2
Columbus	AEP Ohio (Columbus Southern Power Company)	7.5
Columbus	City of Columbus	10.5
Dallas	TXU Energy	11.0
Denver	Xcel Energy	11.5
Detroit	DTE Energy Company	14.4
El Paso	The Electric Company (El Paso Electric)	10.9
Fort Worth	TXU Energy	11.0
Fresno	Pacific Gas and Electric Company	31.5
Houston	Entergy Texas	9.1
Houston	TXU Energy	11.2
Indianapolis	Indianapolis Power and Light Company	6.4
Jacksonville	Jacksonville Electric Authority	12.2
Kansas City	Kansas City Power and Light	7.4
Las Vegas	NV Energy	12.1
Long Beach	Southern California Edison	34.1
Los Angeles	Los Angeles Department of Water and Power	15.6
Louisville	Louisville Gas and Electric	7.5
Memphis	Memphis Light, Gas and Water Division	8.5
Mesa	City of Mesa	9.9
Miami	Florida Power and Light Company	12.8
Milwaukee	WE Energies	13.3
Minneapolis	Xcel Energy	10.3
Nashville	Nashville Electric Service	9.9

New York City	Con Edison	19.2
Oakland	Pacific Gas and Electric Company	36.8
Oklahoma City	Oklahoma Gas and Electric Company	7.0
Omaha	Omaha Public Power District	9.4
Philadelphia	PECO Energy Company	17.4
Phoenix	APS	14.8
Portland	Portland General Electric	11.5
Portland	Pacific Power	11.0
Raleigh	Duke Energy	8.9
Raleigh	Progress Energy	9.8
Raleigh	Piedmont Electric Membership Corporation	11.1
Sacramento	Sacramento Municipal Utility District	15.7
San Antonio	San Antonio Public Service (CPS Energy)	8.8
San Diego	San Diego Gas and Electric	29.2
San Francisco	Pacific Gas and Electric Company	34.7
San Jose	Pacific Gas and Electric Company	33.6
Seattle	Seattle City Light	9.6
Tucson	Tucson Electric Power	10.9
Tulsa	Public Service Company of Oklahoma	6.6
Virginia Beach	Dominion Virginia Power	9.2
Washington, DC	Pepco	12.7
Wichita	Westar Energy	8.6

Table B.2. Time-of-Use Rate—EV and House on Same Meter (TOU-WH)

City	Utility	Hourly Rates on Cheapest TOU-WH Plan (cents/kWh, rounded to the nearest cent)																							
		Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	**Avg.***
Albuquerque	Public Service Company of New Mexico	7	7	7	7	7	7	7	7	14	14	14	14	14	14	14	14	14	14	14	14	7	7	7	7	**8.4**
Atlanta	Georgia Power	5	5	5	5	5	5	5	10	10	10	10	10	10	10	14	14	14	14	14	10	10	10	10	5	**7.4**
Baltimore	Baltimore Gas and Electric Company	9	9	9	9	9	9	9	10	10	10	11	10	10	10	10	10	10	11	11	11	10	9	9	9	**9.2**
Boston	NSTAR	12	12	12	12	12	12	12	12	15	19	19	19	19	19	19	19	19	19	15	15	15	12	12	12	**12.7**
Charlotte	Duke Energy	10	10	10	10	10	10	10	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	**10.4**
Chicago	ComEd	8	8	8	8	9	9	10	10	11	11	11	11	11	11	11	12	12	12	12	12	11	10	9	9	**10.6**
Colorado Springs	Colorado Springs Utilities	6	6	6	6	6	6	6	6	6	6	6	10	10	10	10	10	14	14	10	10	10	10	6	6	**7.1**
Columbus	AEP Ohio (Columbus Southern Power Company)	6	6	6	6	6	6	6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	6	6	**7.5**
Denver	Xcel Energy	9	9	9	9	9	9	9	9	9	9	9	9	9	9	13	13	13	13	13	13	9	9	9	9	**9.6**
Detroit	DTE Energy Company	10	10	10	10	10	10	10	10	10	10	10	15	15	15	15	15	15	15	15	10	10	10	10	10	**11.2**
El Paso	The Electric Company (El Paso Electric)	9	9	9	9	9	9	9	9	9	9	9	9	13	13	13	13	13	13	13	13	9	9	9	9	**9.7**
Fresno	Pacific Gas and Electric Company	18	18	18	18	18	18	18	28	28	28	28	28	28	28	35	35	35	39	39	39	39	28	28	28	**20.8**
Houston	Entergy Texas	6	6	6	6	6	6	9	9	9	9	6	6	6	10	10	10	10	10	13	13	13	9	6	6	**7.2**

Jacksonville	Jacksonville Electric Authority	8	8	8	8	8	8	11	11	11	11	8	8	12	12	12	12	12	12	14	14	14	11	8	8	**10.1**
Kansas City	Kansas City Power and Light	8	8	8	8	8	8	8	8	8	8	8	8	8	10	10	10	10	10	10	8	8	8	8	8	**8.3**
Las Vegas	NV Energy	6	6	6	6	6	6	6	6	6	6	6	6	6	6	12	12	12	12	12	6	6	6	6	6	**6.5**
Long Beach	Southern California Edison	16	16	16	16	16	16	24	24	24	24	32	32	32	32	32	32	32	32	24	24	24	24	24	24	**19.5**
Los Angeles	Los Angeles Department of Water and Power	9	9	9	9	9	9	9	9	9	9	12	12	12	14	14	14	14	12	12	12	9	9	9	9	**10.4**
Louisville	Louisville Gas and Electric	5	5	5	5	5	5	9	9	9	9	9	9	7	9	9	9	9	9	9	7	7	7	5	5	**5.9**
Miami	Florida Power and Light Company	8	8	8	8	8	8	10	10	10	10	8	8	11	11	11	11	11	11	14	14	14	10	8	8	**9.9**
Milwaukee	WE Energies	5	5	5	5	5	5	5	5	20	20	20	20	20	20	20	20	20	20	20	20	5	5	5	5	**7.6**
Minneapolis	Xcel Energy	4	4	4	4	4	4	4	4	4	13	13	13	13	13	13	13	13	13	13	13	13	4	4	4	**6.5**
New York City	Con Edison	7	7	7	7	7	7	7	7	7	7	25	25	25	25	25	25	25	25	25	25	25	25	7	7	**10.0**
Oakland	Pacific Gas and Electric Company	19	19	19	19	19	19	19	29	29	29	29	29	29	29	36	36	36	40	40	40	40	29	29	29	**24.6**
Oklahoma City	Oklahoma Gas and Electric Company	5	5	5	5	5	5	5	5	5	5	5	5	5	5	10	10	10	10	10	5	5	5	5	5	**5.3**
Phoenix	APS	6	6	6	6	6	6	6	6	6	6	6	6	18	18	18	22	22	22	18	6	6	6	6	6	**7.7**
Portland	Portland General Electric	7	7	7	7	7	7	12	12	12	12	10	10	10	10	10	12	12	14	14	14	10	10	7	7	**8.4**
Portland	Pacific Power	10	10	10	10	10	10	11	11	11	11	10	10	10	10	10	10	13	14	14	14	10	10	10	10	**10.1**

Raleigh	Duke Energy	10	10	10	10	10	10	10	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	**10.4**
Raleigh	Progress Energy	5	5	5	5	5	5	12	12	12	12	16	16	16	9	9	9	16	16	16	16	16	5	5	5	**6.8**
Raleigh	Piedmont Electric Membership Corporation	6	6	6	6	6	6	14	14	14	14	6	6	6	16	16	16	16	16	6	6	6	6	6	6	**7.3**
Sacramento	Sacramento Municipal Utility District	8	8	8	8	8	8	8	9	9	9	8	8	8	8	14	14	14	15	15	15	8	8	8	8	**9.4**
San Diego	San Diego Gas and Electric	15	15	15	15	15	17	17	17	17	17	17	17	22	22	22	22	22	22	17	17	17	17	17	17	**15.4**
San Francisco	Pacific Gas and Electric Company	19	19	19	19	19	19	19	29	29	29	29	29	29	29	36	36	36	40	40	40	40	29	29	29	**23.2**
San Jose	Pacific Gas and Electric Company	18	18	18	18	18	18	18	28	28	28	28	28	28	28	36	36	36	39	39	39	39	28	28	28	**22.3**
Tucson	Tucson Electric Power	8	8	8	8	8	8	10	10	10	10	8	8	9	9	11	11	11	13	12	12	10	8	8	8	**9.3**
Tulsa	Public Service Company of Oklahoma	5	5	5	5	5	5	5	5	5	5	5	5	5	5	8	8	8	8	8	5	5	5	5	5	**5.9**
Virginia Beach	Dominion Virginia Power	5	5	5	5	5	5	5	11	11	11	11	8	8	8	8	8	8	14	14	14	14	8	5	5	**6.5**
Washington, DC	Pepco	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	**15.5**

**Average rate is calculated using the charge profile described in the methodology.*

Table B.3. Time-of-Use Rate—EV Metered Separately (TOU-EV)

City	Utility	Hourly Rates on Cheapest Plan (cents/kWh, rounded to the nearest cent)																							
		Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	**Avg.***
Albuquerque	Public Service Company of New Mexico	7	7	7	7	7	7	7	7	14	14	14	14	14	14	14	14	14	14	14	14	7	7	7	7	**8.4**
Atlanta	Georgia Power	5	5	5	5	5	5	5	10	10	10	10	10	10	10	14	14	14	14	14	10	10	10	10	5	**7.4**
Baltimore	Baltimore Gas and Electric Company	9	9	9	9	9	9	9	10	10	10	11	10	10	10	10	10	10	11	11	11	10	9	9	9	**9.2**
Boston	NSTAR	12	12	12	12	12	12	12	12	15	19	19	19	19	19	19	19	19	19	15	15	15	12	12	12	**12.7**
Charlotte	Duke Energy	10	10	10	10	10	10	10	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	**10.4**
Colorado Springs	Colorado Springs Utilities	6	6	6	6	6	6	6	6	6	6	6	10	10	10	10	10	14	14	10	10	10	10	6	6	**7.1**
Columbus	AEP Ohio (Columbus Southern Power Company)	6	6	6	6	6	6	6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	6	6	**7.5**
Denver	Xcel Energy	9	9	9	9	9	9	9	9	9	9	9	9	9	9	13	13	13	13	13	13	9	9	9	9	**9.6**
Detroit	DTE Energy Company	9	9	9	9	9	9	9	9	9	16	16	16	16	16	16	16	16	16	16	16	16	16	16	9	**10.7**
El Paso	The Electric Company (El Paso Electric)	9	9	9	9	9	9	9	9	9	9	9	9	13	13	13	13	13	13	13	13	9	9	9	9	**9.7**
Fresno	Pacific Gas and Electric Company	5	5	5	5	5	5	5	8	8	8	8	8	8	8	15	15	15	17	17	17	17	8	8	8	**6.3**
Houston	Entergy Texas	6	6	6	6	6	6	9	9	9	9	6	6	6	10	10	10	10	10	13	13	13	9	6	6	**7.2**

Indianapolis	Indianapolis Power and Light Company	4	4	4	4	4	4	4	4	7	7	8	8	8	8	10	10	10	10	10	8	5	5	4	4	**5.2**
Kansas City	Kansas City Power and Light	8	8	8	8	8	8	8	8	8	8	8	8	8	10	10	10	10	10	10	8	8	8	8	8	**8.3**
Las Vegas	NV Energy	4	4	4	4	4	4	6	6	6	6	6	6	6	6	12	12	12	12	12	6	6	6	4	4	**5.4**
Long Beach	Southern California Edison	11	11	11	11	11	11	11	11	11	11	11	11	25	25	25	25	25	25	25	25	25	11	11	11	**13.2**
Los Angeles	Los Angeles Department of Water and Power	9	9	9	9	9	9	9	9	9	9	12	12	12	14	14	14	14	12	12	12	9	9	9	9	**10.4**
Louisville	Louisville Gas and Electric	5	5	5	5	5	5	9	9	9	9	9	9	7	9	9	9	9	9	9	7	7	7	5	5	**5.9**
Miami	Florida Power and Light Company	8	8	8	8	8	8	10	10	10	10	8	8	11	11	11	11	11	11	14	14	14	10	8	8	**9.9**
Milwaukee	WE Energies	5	5	5	5	5	5	5	5	20	20	20	20	20	20	20	20	20	20	20	20	5	5	5	5	**7.6**
Minneapolis	Xcel Energy	4	4	4	4	4	4	4	4	4	13	13	13	13	13	13	13	13	13	13	13	13	4	4	4	**6.5**
New York City	Con Edison	7	7	7	7	7	7	7	7	7	7	25	25	25	25	25	25	25	25	25	25	25	25	7	7	**10.0**
Oakland	Pacific Gas and Electric Company	6	6	6	6	6	6	6	9	9	9	9	9	9	9	16	16	16	18	18	18	18	9	9	9	**8.1**
Oklahoma City	Oklahoma Gas and Electric Company	7	7	7	7	7	7	7	7	7	7	7	7	7	7	12	12	12	12	12	7	7	7	7	7	**7.6**
Phoenix	APS	6	6	6	6	6	6	6	6	6	6	6	6	18	18	18	22	22	22	18	6	6	6	6	6	**8.7**
Portland	Portland General Electric	7	7	7	7	7	7	11	11	11	11	9	9	9	9	9	11	11	13	13	13	9	9	7	7	**7.6**
Portland	Pacific Power	10	10	10	10	10	10	11	11	11	11	10	10	10	10	10	10	13	14	14	14	10	10	10	10	**10.1**

Raleigh	Duke Energy	10	10	10	10	10	10	10	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	**10.4**
Raleigh	Progress Energy	5	5	5	5	5	5	12	12	12	12	16	16	16	9	9	9	16	16	16	16	16	5	5	5	**6.8**
Raleigh	Piedmont Electric Membership Corporation	6	6	6	6	6	6	14	14	14	14	6	6	6	16	16	16	16	16	6	6	6	6	6	6	**7.3**
Sacramento	Sacramento Municipal Utility District	8	8	8	8	8	8	8	9	9	9	8	8	8	8	14	14	14	15	15	15	8	8	8	8	**9.4**
San Diego	San Diego Gas and Electric	15	15	15	15	15	17	17	17	17	17	17	17	22	22	22	22	22	22	22	22	17	17	17	17	**15.5**
San Francisco	Pacific Gas and Electric Company	6	6	6	6	6	6	6	9	9	9	9	9	9	9	16	16	16	18	18	18	18	9	9	9	**7.6**
San Jose	Pacific Gas and Electric Company	5	5	5	5	5	5	5	8	8	8	8	8	8	8	15	15	15	17	17	17	17	8	8	8	**6.6**
Tucson	Tucson Electric Power	6	6	6	6	6	6	8	8	8	8	6	6	7	7	9	9	9	12	10	10	9	6	6	6	**7.3**
Tulsa	Public Service Company of Oklahoma	6	6	6	6	6	6	6	6	6	6	6	6	6	6	8	8	8	8	8	6	6	6	6	6	**6.8**
Virginia Beach	Dominion Virginia Power	5	5	5	5	5	5	5	11	11	11	11	8	8	8	8	8	8	14	14	14	14	8	5	5	**6.5**
Washington, DC	Pepco	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	**15.5**
**Average rate is calculated using the charge profile described in the methodology.*																										

Table B.4. Charging Costs for the 50 Largest Cities in the Lower 48 States

City	Utility	Annual Charging Costs ($/year)			Annual Savings Compared with 27 mpg Gasoline Vehicle ($/year)			Annual Charging Costs, Off-Peak Only ($/year)	
		Standard Rate Plan	TOU-WH	TOU-EV	Standard Rate Plan	TOU-WH	TOU-EV	TOU-WH	TOU-EV
Albuquerque	Public Service Company of New Mexico	520	310	310	900	1,110	1,110	270	270
Arlington	TXU Energy	410			1,010				
Atlanta	Georgia Power	420	270	270	1,000	1,150	1,150	230	230
Austin	Austin Energy	400			1,020				
Baltimore	Baltimore Gas and Electric Company	400	340	340	1,020	1,080	1,080	330	330
Boston	NSTAR	570	470	470	850	950	950	440	440
Charlotte	Duke Energy	330	390	390	1,090	1,030	1,030	380	380
Chicago	ComEd	430	390		990	1,030		360	
Cleveland	Cleveland Public Power	440			980				
Cleveland	First Energy—The Illuminating Company	280			1,140				
Colorado Springs	Colorado Springs Utilities	340	260	260	1,080	1,160	1,160	240	240
Columbus	AEP Ohio (Columbus Southern Power Company)	280	280	280	1,140	1,140	1,140	240	240
Columbus	City of Columbus	390			1,030				

Dallas	TXU Energy	410			1,010				
Denver	Xcel Energy	430	360	360	990	1,060	1,060	340	340
Detroit	DTE Energy Company	530	420	400	890	1,000	1,020	400	350
El Paso	The Electric Company (El Paso Electric)	410	360	360	1,010	1,060	1,060	350	350
Fort Worth	TXU Energy	410			1,010				
Fresno	Pacific Gas and Electric Company	1170	770	230	250	650	1,190	660	180
Houston	Entergy Texas	340	270	270	1,080	1,150	1,150	240	240
Houston	TXU Energy	420			1,000				
Indianapolis	Indianapolis Power and Light Company	240		190	1,180		1,230		170
Jacksonville	Jacksonville Electric Authority	450	370		970	1,050		350	
Kansas City	Kansas City Power and Light	270	310	310	1,150	1,110	1,110	310	310
Las Vegas	NV Energy	450	240	200	970	1,180	1,220	230	170
Long Beach	Southern California Edison	1270	730	490	150	690	930	630	430
Los Angeles	Los Angeles Department of Water and Power	580	390	390	840	1,030	1,030	360	360
Louisville	Louisville Gas and Electric	280	220	220	1,140	1,200	1,200	200	200
Memphis	Memphis Light, Gas and Water Division	320			1,100				
Mesa	City of Mesa	370			1,050				

Miami	Florida Power and Light Company	480	370	370	940	1,050	1,050	340	340
Milwaukee	WE Energies	500	280	280	920	1,140	1,140	200	200
Minneapolis	Xcel Energy	390	240	240	1,030	1,180	1,180	190	190
Nashville	Nashville Electric Service	370			1,050				
New York City	Con Edison	710	370	370	710	1,050	1,050	260	260
Oakland	Pacific Gas and Electric Company	1370	920	300	50	500	1,120	790	240
Oklahoma City	Oklahoma Gas and Electric Company	260	200	280	1,160	1,220	1,140	180	270
Omaha	Omaha Public Power District	350			1,070				
Philadelphia	PECO Energy Company	650			770				
Phoenix	APS	550	290	330	870	1,130	1,090	240	270
Portland	Portland General Electric	430	310	280	990	1,110	1,140	280	250
Portland	Pacific Power	410	380	380	1,010	1,040	1,040	370	370
Raleigh	Duke Energy	330	390	390	1,090	1,030	1,030	380	380
Raleigh	Progress Energy	360	250	250	1,060	1,170	1,170	190	190
Raleigh	Piedmont Electric Membership Corporation	410	270	270	1,010	1,150	1,150	230	230
Sacramento	Sacramento Municipal Utility District	580	350	350	840	1,070	1,070	330	330
San Antonio	San Antonio Public Service (CPS Energy)	330			1,090				

San Diego	San Diego Gas and Electric	1090	570	580	330	850	840	540	540
San Francisco	Pacific Gas and Electric Company	1290	860	280	130	560	1,140	750	230
San Jose	Pacific Gas and Electric Company	1250	830	250	170	590	1,170	720	190
Seattle	Seattle City Light	360			1,060				
Tucson	Tucson Electric Power	400	350	270	1,020	1,070	1,150	330	250
Tulsa	Public Service Company of Oklahoma	240	220	250	1,180	1,200	1,170	210	250
Virginia Beach	Dominion Virginia Power	340	240	240	1,080	1,180	1,180	200	200
Washington, DC	Pepco	470	580	580	950	840	840	570	570
Wichita	Westar Energy	320			1,100				

Notes:
(1) Gasoline vehicle efficiency of 27 miles per gallon
(2) 11,000 miles per year of driving
(3) $3.50-per-gallon gasoline

See the main report for references.