Life Cycle Assessment and Grid Electricity: What Do We Know and What Can We Know?

CHRISTOPHER L. WEBER,*,† PAULINA JARAMILLO,† JOE MARRIOTT,‡ AND CONSTANTINE SAMARAS§,||

Department of Civil and Environmental Engineering and Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, Pennsylvania 15213, Department of Civil and Environmental Engineering, University of Pittsburgh, Pittsburgh, Pennsylvania 15260, and RAND Corporation, Pittsburgh, Pennsylvania 15213

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The generation and distribution of electricity comprises nearly 40% of U.S. CO_2 emissions, as well as large shares of SO_2, NO_x, small particulates, and other toxins. Thus, correctly accounting for these electricity-related environmental releases is of great importance in life cycle assessment of products and processes. Unfortunately, there is no agreed-upon protocol for accounting for the environmental emissions associated with electricity, as well as significant uncertainty in the estimates. Here, we explore the limits of current knowledge about grid electricity in LCA and carbon footprinting for the U.S. electrical grid, and show that differences in standards, protocols, and reporting organizations can lead to important differences in estimates of CO_2, SO_2, and NO_x emissions factors. We find a considerable divergence in published values for grid emissions factor in the U.S. We discuss the implications of this divergence and list recommendations for a standardized approach to accounting for air pollution emissions in life cycle assessment and policy analyses in a world with incomplete and uncertain information.

Introduction

Electricity usage and its associated primary energy consumption and emissions are important contributors to the life cycle impacts of many products and processes, as well as to greenhouse gas inventories of entities, products, and countries (*1*−*3*). The types of electricity generation in a region constitute one of the main drivers in regional greenhouse gas intensity and in region-specific life cycle inventories (*4*). However, despite its importance, the electricity industry is unique for life cycle assessment (LCA) and policy analysis because while it is straightforward to measure electricity usage, it is impossible to trace the electricity generated in a given power plant through the transmission and distribution system to a specific electricity consumer.

* Corresponding author e-mail: clweber@andrew.cmu.edu.
† Department of Civil and Environmental Engineering, Carnegie Mellon University.
‡ University of Pittsburgh.
§ RAND Corporation.
|| Department of Engineering and Public Policy, Carnegie Mellon University.

For this reason, it is common in LCA and carbon footprinting to create and utilize emissions factors, or average amount of a pollutant per unit activity, for the use of grid electricity, such as g CO_2/kWh consumed (*1, 5*). These factors are different from the traditional type of emissions factor because they represent not a single point source of emissions but an aggregate estimate of emissions from a broad system of power generators. Thus, an LCA practitioner's assumption about the emissions factor of electricity generation involves either an explicit or implicit assumption about the mix of methods used to generate purchased electricity at the given location and time. This inability to trace electrons from producer to consumer is similar to the well-known problem of allocation for coproducts in LCA (*6*), though in reverse; rather than one process making several different products, several distinct processes produce a single indistinguishable good (We thank a reviewer for making this analogy.). Of course, these emissions factors will vary in both time and space according to which power generation assets are producing the electricity currently supplying the grid. Because energy statistics tend to be collected by political borders, a common assumption is the use of national fuel production mixes to calculate emissions factors for electricity generation (for example, see (*7*)).

Changes to this critical assumption can raise or lower the CO_2 emissions associated with a product or service by a factor of 100 or more. For this reason, several studies have attempted to quantify the emissions associated with electricity supply and demand in different areas and times (*8*−*12*). Yet despite the clear importance of this assumption, there is little agreement as to the proper geographic and temporal scales for calculating such factors for use in life cycle assessment of products. Furthermore, this uncertainty (which results from the variability of fuels and technologies used for electricity generation) comes at a time when critical policy and economic choices are being made based on the outcomes of these calculations: increasingly, corporations are publicizing claims of carbon neutrality or labeling carbon footprints on their products, carbon offsets are being sold for decreased electricity usage in efficiency projects, and proposed climate polices such as low carbon fuel standards and border adjustment measures are starting to utilize LCA techniques (*2, 13*).

In this paper, we explore the limits of current knowledge about grid electricity in LCA and carbon footprinting (*1, 2*) through a case study of the U.S. electrical grid. We investigate the uncertainty in CO_2, SO_2, and NO_x emissions factors at various geographic levels in the continental U.S., and further discuss the applicability of various mix choices to particular analysis circumstances. (CO_2 is the dominant greenhouse gas in power generation, representing well over 99% of direct GWP (*14*)). By examining the variability of various reported emissions factors for different locales in the U.S. our two goals are first, to explore the extent of grid emissions factor uncertainty in different parts of the U.S. grid, and second, to make the case for a standardized approach to accounting for grid emissions in life cycle and policy analyses. The following section provides necessary background information for the discussion, followed by case study data and results. We conclude with a discussion of the implications of the current uncertainty and a proposal for standardization.

Background

Electricity Systems. Despite the importance of electricity to the economy and the environment, it is often seen as a homogeneous commodity and treated casually, as if all

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kilowatt-hours were equal. Yet, while electrons are equal when they are consumed, generating them is not (see Supporting Information). Many different fuels/sources are used to generate electricity and they all have different economic and environmental profiles. Around 70% of power in the U.S. is generated using carbon-intensive fossil fuels. Another 20% of electricity comes from carbon-free, but nuclear waste-producing nuclear plants (*15*). Only a small fraction—between 2 and 3%—of electricity is generated with renewable (low-carbon) sources such as wind, geothermal, biomass, or solar thermal and photovoltaic (*15*) (~7% from conventional hydroelectric), and each of these have varying issues of cost, availability, and ecosystem disruption.

In addition to different generation costs and impacts, the demand patterns over the day and season complicate electricity markets. Because of the need to instantaneously match supply and demand across the entire grid, power system operators rely on the unique characteristics of different generation assets to ensure grid stability and power quality—thus electricity consumed at different times can be quite different. For instance, coal, nuclear, and hydroelectric plants provide a relatively steady supply of electricity to meet the base load demand, while natural gas plants provide some base load but mostly peak generation and load following capability. Outputs from some sources vary with season as well, particularly hydroelectric dams. A further discussion of accounting for electricity using marginal or time-specific methods is given in the Supporting Information.

Adding further to system complexity is the way electricity markets function. Taking the U.S. as an example, for most of the 20th century the U.S. electricity industry was organized as local monopolies, regulated by the states, generating and distributing the electricity in small local grids. However, with deregulation in the 1990s, power generation became more competitive and transmission connected remote customers with remote generators, making it virtually impossible to know where the electricity purchased by an individual consumer came from. In response to utility deregulation in the U.S., U.K., and elsewhere, there was an attempt made to define methods of tracing specific flows of electricity between sources and customers, largely for the purposes of charging customers for marginal generation or allocating resistive losses across the transmission system (*16*–*18*). Multiple reviews of these methods, and an introduction of game theory concepts did not lead to consensus within the power systems community (*19*–*22*). Work continues, but the literature remains largely theoretical, and does not lend itself to a practical application like calculating customer-specific emissions (*23*–*25*).

Finally, a caveat about the work presented in this paper should be noted: some utilities have entered into agreements to supply specific types of electricity (such as "green" power) to specific users, further dividing the physical electron path along grids and the contract path of production and sales. Of course, even if a specific facility enters into a contract with a certain wind farm operator to supply all of the facility's electricity demand, unless the facility is connected solely to the wind farm and not the electricity grid, electrons physically arriving at this facility will be electrons generated from a mix of sources on the grid (*3*). LCA standards however, have rightfully dealt with this situation separately from regular power purchases (see next section) by allowing the carbon/renewable energy credits to be allocated to the facilities contracting with the wind farm. The work presented in this paper only refers to retail power purchases from the interconnected grid.

Standards for Life Cycle Assessment and Carbon Footprinting. The impossibility of tracing electron flow precisely, combined with the importance of electricity to life cycle environmental impacts (see Supporting Information), implies the need for a standard system for allocating the impacts of grid electricity to its users. Since there is no "correct" answer, the LCA community needs to better understand and represent the uncertainty associated with the source of the electricity purchased by individual consumers. However, no clear framework to incorporate this uncertainty has emerged. Within published standards for life cycle assessment and footprinting, the International Standards Organization's ISO 14040 series of standards, the British Standards Institute's PAS 2050, and the World Resources Institute/World Business Council on Sustainable Development's Greenhouse Gas Protocol are arguably the most important and are the most widely used (*1, 5, 7*). Each contains similar, broad language about choosing an electricity grid mix appropriate to the problem at hand. None however, defines how appropriateness should be evaluated. For example, the British Standards Institute's PAS 2050 specification states that one should use "secondary data that is as specific to the product system as possible (e.g. average electricity supply emission factor for the country in which the electricity is used)" (*7*). The ISO standard, the most cited standard in LCA, is perhaps even more general: "for the production and delivery of electricity, account shall be taken of the electricity mix, the efficiencies of fuel combustion, conversion, transmission and distribution losses." (*5*). The Greenhouse Gas Protocol (GHGP) produces an emissions tool for calculating impacts from purchased electricity, using country-average production mixes for non-U.S. countries and EPA's eGrid subregions for within the U.S. (see below for more detail) (*1*). An analysis of the current LCA databases such as the Ecoinvent database in Europe and the NREL LCI database in the U.S. (*12, 26*) shows a variety of geographical detail, from country-level mixes (with and without the inclusion of imports) in the U.S. and EU countries to subnational mixes for the U.S., and international mixes for some European power markets. (We thank a reviewer for this example.)

Methods and Data

In this work we track the different ways in which grid electricity is accounted for in current LCA and footprinting work by collecting emissions factors for CO_2, SO_2, and NO_x and calculating a statistical measure of variance among factors. We focus on the continental U.S. as a case study for the importance of the geographical boundaries at which electricity emissions factors are estimated. We find there is some justification for a multinational definition including all of North America. In North America, specifically, there is some small flow of power between the United States and Canada (U.S. is a net importer of approximately 23 TWh from Canada compared to 4000 TWh generated), and, to a lesser extent, between the U.S. and Mexico (1 TWh) (*14*). However, there are several reasons for such a U.S.-centric analysis, including the small amounts involved, limited data availability, the large importance of the U.S. electricity sector in national and global CO_2 emissions, and the national focus of many of the methods of LCA and carbon footprinting (*1, 14, 26, 27*). Further, despite this focus on the U.S., the same basic ideas apply in many other places with large interconnected electrical grids, such as continental Europe.

Two main dimensions are important when estimating the environmental impacts of purchased electricity: temporal and spatial. We assume that yearly temporal data is preferred, both theoretically due to capturing annual climatic variation, as well as practically, as emissions factors and other LCA data (such as energy use, process changes, etc.) are unlikely to utilize time-of-day or seasonal specificity due to time and data constraints. Thus we primarily assess the geographic uncertainty in assessing the spatially averaged emissions factor of purchased electricity at any point in the continental

U.S. Greenhouse gas (GHG) emissions are of special interest because of increased concerns over climate change and the potential implementation of GHG regulations in the coming years. The same principles, however, will apply for other emissions associated with power generation, such as oxides of nitrogen and sulfur, mercury, etc. In fact, other types of emissions may vary in space considerably more, as the prevalence of control technology and the link of certain emissions (sulfur and mercury, for instance) with only one type of generation (coal). Further, increasing interest is being paid to SO_2 and NO_x due to direct and indirect radiative forcing effects (*28*). We note that upstream supply chains for fuel production would act to increase the overall uncertainty of the system, though these parameters are not explicitly included in our assessment because any uncertainty in site-level impacts will only be increased slightly by including upstream supply chains of electricity generation (see Supporting Information).

We collected several sources of emissions factors, though most data sets are based primarily on the U.S. EPA's eGrid data for year 2005 (*14*). The eGrid data set includes fuel consumption, emissions, resource mix, generation, and location for practically all electric generators in the U.S. The data are given at a plant, boiler, and generator level of detail. We compare derived direct emissions factors (summing emissions and net generation in each region to obtain a factor of g pollutant/kWh generated) for several potential regional delineations of the electrical grid. While standards make it clear that line losses should also be region-specific (*7*), we ignore line losses for simplicity, noting that the regional average line loss will clearly depend on the area over which the grid is averaged. The following paragraphs describe the different regional delineations, shown visually in the Supporting Information.

The largest potential region considered is the U.S. continental average. We derive an emissions factor for the entire grid from eGrid for consistency. It reports a 2005 annual net generation of 4040 TWh, resulting in ~2700 Gg of CO_2 emissions, for an average national emissions factor of approximately 0.69 kg CO_2/kWh (*14*). National average SO_2 and NO_x emission factors were calculated similarly to be 2.8 and 1.0 mg/kWh, respectively. At a subnational level a number of potential regional delineations are possible. At a slightly smaller spatial scale than the continental delineation, there is reason to split the continental U.S. into 3 regions based on electrical grid connectivity—the so-called Eastern and Western Interconnects and the Texas Interconnect (*26*). The Texas Interconnect, or the Electric Reliability Council of Texas (ERCOT), contains the majority of Texas while the Eastern and Western Interconnects split the rest of the Continental country vertically from Montana through New Mexico (see Supporting Information).

An even smaller subnantional delineation is represented in the GHGP indirect emissions from purchased electricity calculator, which utilizes 24 grid delineations defined in eGrid, developed from boundaries of the North American Energy Reliability Corporation (NERC) and referred to as eGrid subregions (*29*). Alternatively, because of the ways electricity markets have been organized since deregulation, another potential delineation should be considered—the level of grid operation, either independent system operators (ISOs) or regional transmission operator (RTO) (*30*). These regions are somewhat similar to those of NERC regions that help to delineate eGrid subregions; however market deregulation has changed borders in some areas, particularly the Midwest (Midwest ISO) and the Mid-Atlantic area of the PJM Interconnection (see Supporting Information). We placed generation plants from eGrid into ISO/RTO regions using NERC borders, latitude and longitude data, state borders, and data from previous work (*31*).

Finally, the smallest delineation we consider results from the data collected by the U.S. Energy Information Administration, which has run a voluntary GHG reporting program since the passage of 1992 Energy Policy Act, referred to as the 1605(b) program (for the name of the form on which the emissions are reported). This program's reported emissions factor database utilizes state borders by grouping states into regions with identical emissions factors (*32*). This program's use of state delineations (along with political realities in a federal system) provides some justification for using state-specific emissions factors, which we take from estimates for production as well as consumption (taking into account interstate trade in electricity) done by Marriott and Matthews (*33*).

In summary, we combine these different data sets of regional emissions factors (*10, 26, 29, 33*) with estimates for national and ISO/RTO-level factors derived from eGrid (*14*) to illustrate the uncertainty in reported electricity emissions factor by region. This data set yields 7 independent estimates (national, interconnect, state production, state consumption, ISO/RTO, eGrid subregion, and EIA region) of the electricity emissions factor (g CO_2/kWh) for every combination of U.S. state, eGrid subregion, and grid operator (ISO/RTO). While 7 data sets were consulted, a high level of correlation exists among the geographical areas of the different data sets; i.e., where the state border is also the ISO/RTO border, etc. However, where multiple similar borders existed these multiple data were still included in the uncertainty calculations because electricity emissions factors represent estimates of what is in practice an unknowable number (see above) and thus it is the assessed uncertainty range (which may or may not be indicative of the true uncertainty) from known data sources that is important. (The EIA 1605(b) program does not include estimates for SO_2 and NO_x emissions, thus for these pollutants only 6 estimates are available.)

Results

A total of 101 combinations of the input parameters in the continental U.S. (state, subregion, and ISO/RTO) were obtained in GIS, showing that the boundaries of these different delineations vary considerably. We will henceforth label each of these combinations a "district" to distinguish these boundaries from those of ISO/RTO and eGrid regional boundaries. These districts vary considerably in size, ranging from 532,000 km^2 (ERCOT ISO of Texas) to small slivers of area between competing region borders, such as the 1100 km^2 of the state of Georgia in the Tennessee Valley eGrid subregion. The 7 estimated GHG emissions and 6 estimated SO_2 and NO_x factors for each district are shown in Tables SI-3—SI-5 in the Supporting Information.

Figure 1 shows a visualization of the results for CO_2 emissions factors across the continental U.S., while Table 1 shows raw data for a selection of districts. Figure 1 shows the eGrid subregion emissions factor (a), the average factor (b), and uncertainty estimate (coefficient of variation, i.e., the normalized standard deviation, COV = σ/μ, (c)), for each of the 101 districts, as well as the difference between the eGrid subregion and largest national geographical boundaries. We note that this estimate is a representation of neither pure uncertainty or pure variability, since it represents an uncertain mix of generation technologies varying in time and space; nonetheless, we refer to all uncertainty and variability as uncertainty to avoid confusion. A high COV for any single district shows high variation between the different estimates of electricity emissions factor, and thus high uncertainty related to the appropriate CO_2 emissions factor for electricity consumed by an individual user in the region. Because of the importance of GHG emissions to LCA, we focus much of the rest of the discussion on uncertainty in the CO_2

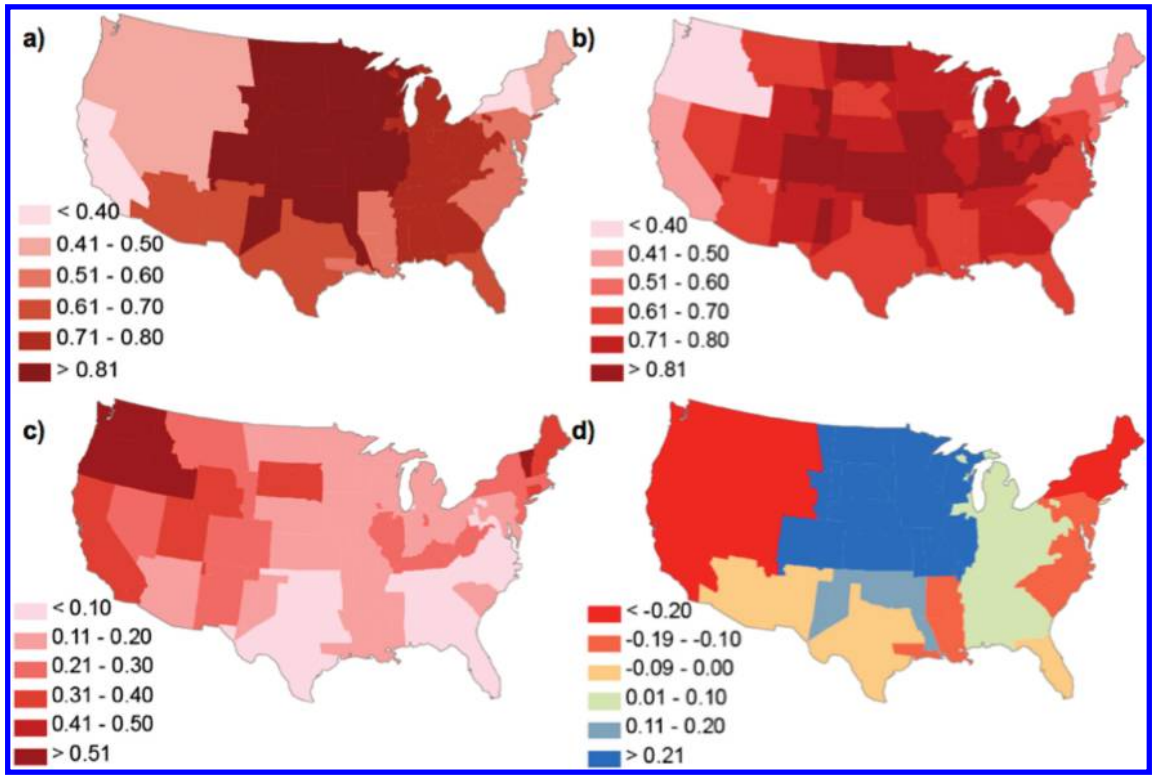

FIGURE 1. Results of GIS statistical analysis (for CO_2; other pollutants shown in Supporting Information): (a) eGrid subregion emissions factors (kg CO_2/kWh), (b) average emissions factor for each district (kg CO_2/kWh), (c) coefficient of variation of CO_2 emissions factor by district, and (d) difference between eGrid subregion emissions factor and U.S. average emissions factor, 0.65 kg CO_2/kWh (kg CO_2/kWh).

TABLE 1. Example District Emissions Factors for CO_2 (shown in kg CO_2/kWh)[a]

district	St Prod	St Cons	ISO	eGrid	EIA	IC	US	mean	st dev	COV
AL-SERC South	0.70	0.70	0.68	0.74	0.69	0.72	0.69	0.70	0.02	0.03
TX-ERCOT ISO	0.68	0.68	0.69	0.66	0.73	0.70	0.69	0.69	0.02	0.03
GA-SERC South	0.73	0.74	0.68	0.74	0.69	0.72	0.69	0.71	0.02	0.03
FL-FRCC	0.67	0.67	0.65	0.63	0.68	0.72	0.69	0.67	0.03	0.04
NY-NY ISO-NPCC NE	0.43	0.43	0.43	0.41	0.47	0.72	0.69	0.51	0.13	0.26
CA-CA ISO-WECC CA	0.29	0.44	0.33	0.36	0.35	0.55	0.69	0.43	0.14	0.33
WA-WECC NW-NWPP	0.13	0.13	0.54	0.45	0.15	0.55	0.69	0.38	0.24	0.62
VT-NE ISO-NPCC NE	0.02	0.02	0.46	0.41	0.47	0.72	0.69	0.40	0.29	0.72

[a] District names are combinations of state abbreviations, ISO/RTO abbreviations, and eGrid subregion abbreviations. See Supporting Information.

emissions factor, with results for SO_2 and NO_x in the Supporting Information. The average CO_2 COV for the 101 districts was 0.19 (i.e., average uncertainty of ±40% at 2σ), ranging from a maximum of 0.70 (Vermont-New England ISO) to a minimum of 0.08 (Texas-ERCOT ISO). COVs for SO_2 and NO_x were on average 135% and 40% higher than for CO_2 respectively, showing that pollutants related to fuel composition of a specific type of generation (such as sulfur in coal) exhibit more uncertainty than carbon content alone.

The districts with largest uncertainty are those with smaller than average or larger than average local or regional emissions factors. As Table 1 and Table SI-1 show, for example, after Vermont (state factor = 20 g CO_2/kWh), the next six highest coefficients of variation were in districts with very low local and regional emissions factors (Washington, Idaho, and Oregon with abundant hydropower generation) or very high local and regional emissions factors (two regions of Utah and Wyoming with substantial coal generation).

As should make sense, the variation in emissions factor is larger in estimates performed at the state level than the larger regional levels of the ISO/RTO, EIA state-based regions, or eGrid subregions, since although they may be important for policy reasons, political borders have little correlation with electricity systems. The larger the region at which the grid is averaged, the closer the estimate comes to the national average emissions factor. This simple observation has rather important consequences, as electricity consumers in certain areas of the country have incentives to choose a larger or smaller area for averaging emission factors to achieve a lower emissions factor. As long as it remains common practice in LCA, carbon footprinting, and GHG reporting to use all these types of emissions factors, individual electricity consumers will have incentive to pick the lowest emissions factor available for their district, be that the local factor for low-polluting regions or the national or interconnect factor for high-polluting regions.

Discussion

Data in an Ideal World. As is often the case with the real world compared to simulated systems, true boundaries for grid electricity are either inconsistent or nonexistent. In an interconnected electricity system, the flow of goods (elec-

tricity) to any node in the system in need of power is only physically limited by (1) transmission constraints and (2) resistive losses in the transmission and distribution system. These factors, coupled with electricity trade between connected regions (*33*), create difficulties in assigning a carbon intensity of electricity to a specific user as well as a geographical boundary with an interconnected system.

To ideally allocate electricity emissions to a specific factory consuming electricity, researchers would have to know which type of plant(s) met the factory's electricity demand, and what losses occurred between production and consumption. For interconnected electricity systems, researchers would thus need to have access to high-resolution dispatch, transmission, and demand data, as well as power flow and resistive loss models, so that flows of power from specific types of generators (e.g., wind or coal) into and out of a region could be estimated on any time scale. However, such data are often proprietary and time-intensive to obtain and to analyze. LCA practitioners and policymakers generally do not possess the resources to construct such models or the temporally explicit demand data to use them. Further, even with the data and resources to perform such an analysis, uncertainty would only be reduced, not eliminated so as to achieve a discrete answer with an acceptable level of precision.

Guidance under Data Constraints. In spite of the considerable uncertainty surrounding the carbon intensity of electricity, reliable and consistent estimates and best practices are required for practitioners, policymakers, and stakeholders. Important decisions and estimations for life cycle environmental emissions cannot be avoided because of the uncertainty involved; adaptable guidelines still require development in spite of this uncertainty. The approach undertaken by the LCA and policy communities to estimate carbon intensity of electricity will depend on the types of research questions asked, and the level of specificity required, but should be a standardized and transparent process. For example, regional emissions factors may be appropriate in analyzing the impact of increased electricity use in the relatively independent ERCOT ISO. On the other hand, the use of a national average emissions factor may be more appropriate for an analysis of the emissions associated with a product or service that is geographically dispersed throughout the U.S., such as retail or health care.

Even in the absence of mandatory regulations or a carbon price signal in the U.S., many companies, municipalities, and institutions are currently using electricity emissions factors to estimate and reduce their GHG emissions. For example, some groups choose to purchase carbon offsets and/or Renewable Energy Certificates (RECs) to claim carbon reductions or carbon neutrality. More than 200 companies, representing about 11% of U.S. 2007 GDP and around 8% of U.S. GHG emissions, have voluntarily developed GHG management and reduction plans with the EPA Climate Leaders Program (*34*). The success of these private efforts may be dependent on the emission factors used to calculate their benchmark. If a company in the Ohio valley wants to voluntarily reduce its carbon footprint, using a national grid average may reduce the effectiveness of their efforts, since the actual emissions associated with their power purchases are higher than average.

While uncertainty with data and quantities will remain no matter how much modeling work is done, standards organizations can provide clear guidance to reduce system boundary choice in determining emissions from grid electricity. In fact, by standardizing how such calculations should be done, such organizations could considerably improve the accounting of electricity emissions through a reduction in *comparative* uncertainty between different product systems and companies. LCA and similar analyses are comparative almost in nature due to the difficulty in interpreting the results of impact assessments, and thus by requiring different analysts to use similar methods and system boundaries, the difference between different alternative products or companies can be reduced substantially even if the underlying uncertainty remains.

In light of our results, standards organizations should discourage the use of arbitrary political borders when assessing the carbon intensity of an interconnected electricity system. While estimating the carbon intensity of electricity purchased by a firm is challenging, estimating or measuring the kWhs of electricity purchased is fairly straightforward. Thus, industry reporting and LCA practitioners should aim to report kWhs used (in addition to assumed grid emissions factor), both on an absolute basis and for a functional unit within an appropriate system boundary. Under this method, normalized comparisons of a specific product (e.g., 0.5 L water bottles) can be made without consideration of the uncertainty in regional differences in grid mix. In addition, other parties interested in using the results of a LCA could use these physical units and apply their own relevant range of emission factors. The U.S. EPA recently considered having facilities report purchased electricity under the proposed mandatory GHG reporting rule, which is a good example of providing relevant data without the need to report very uncertain indirect emissions (*35*).

Nonetheless, if reporting indirect emissions from purchased electricity is either required (as in WRI GHG Protocol) or desired, our results indicate that a range of emissions factors should be used. This range could report at least the emissions based on subregion, grid operator, and Interconnect emissions factors (see Supporting Information). If an entity wanted to guarantee emissions reductions or carbon neutrality for electricity purchaes, it should assume and plan for the highest of the range of emissions factors.

Implication for Public Policy: Dealing with Equity Issues? In addition to voluntary efforts of carbon footprinting, some mandatory environmental policy is beginning to use LCA techniques (see above), and thus these issues are important for policy as well. Yet, assigning a GHG footprint for electricity likely remains within the realm of postnormal science (*36*), where both system uncertainties and decision stakes are high. When uncertainty is assimilated into difficult scientific and environmental decisions, the reduction in complexity creates additional issues and challenges (*37*). In the context of using life cycle assessment to implement regulations on indirect greenhouse gas emissions from electricity use, choosing a standard set of emissions factors for any specific site will result in "winners" and "losers," which raises trade-offs and questions of equity. Dealing with the variability of emissions from electricity generation when designing public policy may be more complex than when private entities are taking voluntary action to reduce their carbon footprint. In the public policy realm, there will always be "winners" and "losers" (as an example, see Figure 1d, which shows the difference between local and national emissions factors). Who the "winners" or "losers" are, and how corresponding equity issues are addressed, will depend on the policy framework being explored. For example, an emissions trading market may grant emissions credits to local distribution companies (LDCs) to reduce the financial impact of the system transition. If these credits were allocated based on large area emissions factors, the LDCs purchasing mostly low-carbon electricity would be "winners". If standard organizations agree to any single method to estimate emissions associated with purchased power, some entities in the losing regions will ultimately question the fairness of this arrangement.

Similarly, it could be argued that using detailed region specific emission factors will result in other equity issues as

well. Many of the decisions about our electricity infrastructure were made in the middle of the 20th century when the government made large investments in building such infrastructure. For example, the government built most of the massive hydroelectric projects of the Pacific Northwest and the Colorado River. The decision to build these projects was obviously made possible by the richness in hydroelectric resources in this area of the country. As a result of these investments, the Pacific Northwest has a very low carbon intensity of electricity generation. If a regional emissions factor is used, companies in this region will be "winners" in performing emissions calculations, as can be seen in Figure 1d. However, the facilities in coal-rich regions, which would be "losers" when regional emission factors are used, would likely question the equity under this scenario. The natural resources of any region play an important role in what type of energy is used in the region, and it could be argued that it is unfair to reward or penalize areas based on the natural availability of resources, something over which the citizens of these areas have no control. It is thus important to acknowledge the existence of these trade-offs and equity issues so that when standards are developed, they can be taken into consideration and properly managed. Without an understanding of the implications associated with the use of different emission factors, public policies may not achieve the desired results, either due to the use of inappropriate numbers when benchmarking emissions or due to public opposition resulting from equity concerns. It is important to realize however, that managing equity issues is always a concern when designing public policy and the existence of complex equity issues should not preclude policies that are crucial for sustainable development in the 21st century.

Final Thoughts. Uncertainty and variability issues in life cycle assessment are starting to be recognized by LCA researchers and practitioners (*6, 7*). It is clear from the results presented in this paper that uncertainty in emissions factors of electricity generation in the U.S. can be considerable and could have significant impacts on the results of life cycle studies. Policymakers have traditionally preferred discrete answers rather than characterizing uncertainty and it is understandable that facilities would prefer a standardized carbon emissions factor rather than deal with complicated ranges. If this is the case, the burden falls on the standards organization for due diligence in characterizing uncertainty and providing clarity on a consistent carbon emissions factor for electricity, including an estimation of upstream impacts, in different national and world regions. These organizations should work toward finding the best balance in terms of accuracy and fairness, though transparency (reporting energy use and assumed factors) and consistency should be stressed above all else, since the uncertainty in emissions factors of electricity used by individual consumers is mostly irreducible. Any consistent choice (e.g., always using national emissions factors or always using regional factors) will be more correct for some regions than others, due to differences in regional electricity markets and transmission constraints. However, this truth must be accepted if consistent, transparent, and reproducible estimates of life cycle impacts are to be made.

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Supporting Information Available

Additional background on power systems, visual depictions of grid mixes, data tables, and references. This material is available free of charge via the Internet at http://pubs.acs.org.

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