Life Cycle Greenhouse Gas Emissions of Coal-Fired Electricity Generation

Systematic Review and Harmonization

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Supporting information is available on the *JIE* Web site

Summary

This systematic review and harmonization of life cycle assessments (LCAs) of utility-scale coal-fired electricity generation systems focuses on reducing variability and clarifying central tendencies in estimates of life cycle greenhouse gas (GHG) emissions. Screening 270 references for quality LCA methods, transparency, and completeness yielded 53 that reported 164 estimates of life cycle GHG emissions. These estimates for subcritical pulverized, integrated gasification combined cycle, fluidized bed, and supercritical pulverized coal combustion technologies vary from 675 to 1,689 grams CO_2-equivalent per kilowatt-hour (g CO_2-eq/kWh) (interquartile range [IQR] = 890–1,130 g CO_2-eq/kWh; median = 1,001) leading to confusion over reasonable estimates of life cycle GHG emissions from coal-fired electricity generation. By adjusting published estimates to common gross system boundaries and consistent values for key operational input parameters (most importantly, combustion carbon dioxide emission factor [CEF]), the meta-analytical process called harmonization clarifies the existing literature in ways useful for decision makers and analysts by significantly reducing the variability of estimates (−53% in IQR magnitude) while maintaining a nearly constant central tendency (−2.2% in median). Life cycle GHG emissions of a specific power plant depend on many factors and can differ from the generic estimates generated by the harmonization approach, but the tightness of distribution of harmonized estimates across several key coal combustion technologies implies, for some purposes, first-order estimates of life cycle GHG emissions could be based on knowledge of the technology type, coal mine emissions, thermal efficiency, and CEF alone without requiring full LCAs. Areas where new research is necessary to ensure accuracy are also discussed.

Introduction

Coal-fired electricity generation represents the largest source of grid-supplied electricity in the United States, accounting for 50% of generation (on average) over the past 15 years (U.S. Energy Information Administration 2010). Partly as a result of coal's major role in electricity generation, multiple life cycle assessments (LCAs) have been conducted to evaluate the environmental impacts of coal-fired electricity generation and to compare these impacts with those of electricity generated using alternatives such as natural gas, wind, solar, and nuclear energy. Moreover, as new coal technologies have been developed, LCAs have focused on comparing the impacts of different coal-fired electricity generation technology options, including subcritical pulverized coal combustion (subcritical), integrated

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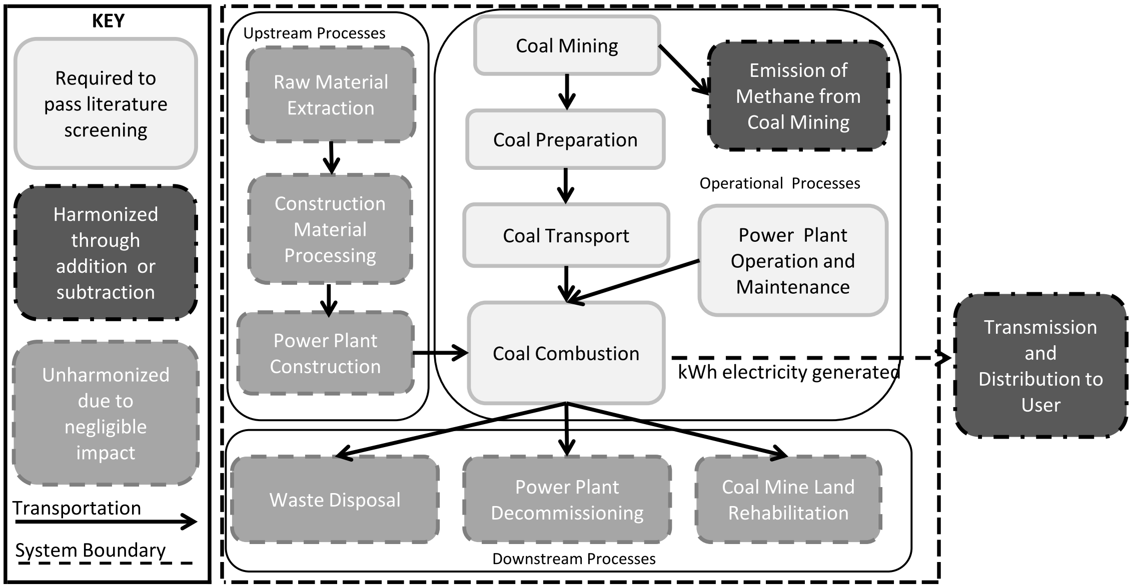

Figure 1 Process flow diagram illustrating the upstream, operational, and downstream life cycle stages of coal-fired electricity generating systems. Inclusion of the ongoing combustion and noncombustion operational stages was required for an estimate to pass the quality screens. System harmonization was applied to emissions of methane from coal mining (added where omitted) and transmission and distribution losses (subtracted where included).

gasification combined cycle (IGCC), fluidized bed (FB), and supercritical pulverized coal combustion (supercritical).

Hundreds of studies have been published evaluating the life cycle environmental impacts of coal-fired electricity generation. Evaluations of the coal life cycle typically include upstream impacts from plant construction and material supply; operating phase impacts related to coal mining and processing, transport of coal to the power plant, coal combustion to generate electricity, and coal power plant operations and maintenance; and downstream impacts related to waste disposal, mine rehabilitation, and plant decommissioning. Estimates of life cycle greenhouse gas (GHG) emissions differ for multiple reasons, including scenario assumptions regarding technology type, technology vintage, location, and coal quality, along with variations in study boundaries associated with the inclusion of plant construction and decommissioning and estimates of coal mine methane generation.

The meta-analysis provided in this article attempts to identify, explain, and, where possible, reduce—through a meta-analytical process called "harmonization"—variability in published estimates of life cycle GHG emissions for utility-scale coal-fired electricity generation systems. This was accomplished by establishing more consistent methods and assumptions regarding characteristics of technical performance, system boundaries, and global warming potential (GWP) of GHGs. The harmonization process seeks to clarify central tendency and to reduce the variability of estimates to better inform decision making and future analyses that rely on such estimates.

Harmonization Methods

Two general types of harmonization are applied to the analyzed studies: system harmonization and technical harmonization. System harmonization is designed to ensure that studies can be fairly compared using a consistent set of included processes and metrics ("apples to apples"). The life cycle stages of coal-fired electricity generation evaluated in the present study are depicted in figure 1 and include the following:

- **Upstream processes**: raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction.
- **Operational processes and fuel cycle:**
  - Ongoing combustion: the coal fuel cycle (FC) includes processes that are modulated by the amount of coal combusted, including mining, preparation, transport, and combustion of coal.
  - Ongoing noncombustion: power plant operation and maintenance, operational nonfuel materials.
- **Downstream processes**: waste disposal, power plant decommissioning, and coal mine rehabilitation.

GHG emission estimates disaggregated by life cycle stage are reported in table S1 in the supporting information available on the Journal's Web site. As part of the system harmonization process, published estimates were adjusted to use consistent GWPs in calculating GHG emissions, to include coal mine methane emissions if they were not originally included in the study's results, and to exclude transmission and distribution (T&D) of electricity from the power plant to end users, as T&D was considered outside the boundary of this study. (See subsequent sections for further description of each harmonization step.)

Technical harmonization was used to adjust results based on the operating conditions of the analyzed power plants, including thermal efficiency and combustion carbon dioxide emission factor (CEF). Subsequent sections describe in greater detail the methods used for technical harmonization. Technical harmonization generates central tendency and variability estimates for life cycle GHG emissions from several coal-fired electricity generating technologies under certain operating conditions. The operating conditions used for technical harmonization in this article were selected to represent modern coal-fired electricity generation technologies operating in the United States. Such results provide a more robust estimate of central tendency and variability in certain analytical applications, but there is also, of course, a need for project-specific estimates. Therefore this article also provides methods for adjusting harmonized results to project-specific conditions to estimate a reasonable range of life cycle GHG emissions for a coal-fired electricity generation project with limited technical and coal life cycle information.

Literature Collection and Screening Approach

A comprehensive search of the English-language literature resulted in 270 references pertaining to life cycle environmental impacts of coal-fired electricity generation. Multiple GHG emission estimates from a single reference were possible if alternative coal-fired electricity generation scenarios or technologies were analyzed. Each estimate of life cycle GHG emissions was independently subjected to two rounds of review, consistent with the established screening methods of the umbrella LCA Harmonization Project conducted by the National Renewable Energy Laboratory. (Several articles reporting harmonized results for other electricity generation technologies, including crystalline silicon photovoltaic [Hsu et al. 2012], thin film photovoltaic [Kim et al. 2012], concentrating solar power [Burkhardt et al. 2012], wind [Dolan and Heath 2012], and nuclear [Warner and Heath 2012], were also produced under the LCA Harmonization Project for publication in this special issue.)[1] Although an entire reference was not necessarily eliminated if only one of its estimates was screened out, most screening criteria applied to the reference as a whole; the results of screening are therefore reported at the level of the reference. Primary screening eliminated 75 references and secondary screening eliminated an additional 142 references. A total of 164 GHG emission estimates drawn from 53 references then underwent the harmonization process. For transparency, citations for references that were eliminated from analysis during the screening process are included in the *Screened References* section of the supporting information on the Web.

Primary Screening

The primary screen eliminated references from further categorization based on several high-level discriminators. References were eliminated at this stage if the reference was

- not a full LCA (less than two phases of the life cycle were evaluated);
- a conference paper less than or equal to five double-spaced pages (or equivalent) in length;
- a trade journal article less than or equal to three published pages (or equivalent) in length;
- a PowerPoint presentation, poster, or abstract;
- published prior to 1980; or
- did not evaluate electricity as a product of the technology.

Secondary Screening

The secondary screen further narrowed the pool of references slated to undergo harmonization by assessing the quality of the studies. Specifically, this screening step assessed

- the quality of the LCA and GHG emission accounting methods (for instance, adhering to guideline 14040 from the International Organization for Standardization [ISO 2006a, 2006b]);
- the completeness of reporting regarding the investigated technology, including adequate description of the inputs and methods such that the results could be traced and trusted. Studies were permitted to use either empirical or theoretical data (noted in table 1); and
- the modern or future relevance of the technology. Both existing and future technologies were included (noted in table 1). To ensure consistency with the broader LCA Harmonization Project, studies were evaluated for the use of obsolete technologies, but no studies that used sound LCA methodologies were excluded for this reason.

To enable technical harmonization, studies were required to either directly report the CEF or to provide sufficient quantitative information for the CEF to be calculated using no exogenous assumptions. Moreover, to avoid transcription error, only GHG emission estimates that were reported numerically (not just graphically) were included for harmonization. Duplicate estimates from one study quoting another or from the same author group publishing the same estimate multiple times were not included. When the magnitude of an estimate could not be explained by common sense, the authors were contacted to confirm certain assumptions. Only one estimate (Babbitt and Lindner 2005) was removed after no reply was received from the authors. Relevant coal-fired electricity generation technologies with a sufficient sample of quality LCAs (minimum of 10 references) included hard coal and lignite combustion using subcritical, IGCC, FB, and supercritical coal combustion technologies. Discussion on the exclusion of IGCC with carbon capture and storage from the harmonized dataset is contained in the supporting information on the Web.

Table 1 Study/technology description and key harmonization parameters for life cycle greenhouse gas (GHG) emission estimates passing screens for quality and relevance. The key to the column headers is available in the table note.

Author	*Pub. Year*	*Tech.*	*Eff. (%)*	*Cap. (MW)*	*Life (years)*	*C.F. (%)*	*Coal Carbon (% C)*	*Coal LHV (MJ/kg)*	*CEF (kg CO_2/ kWh)*	*Coal Meth. Inc.?*	*Temp Vint.*	*Data Type*	*Study Loc.*
Akai et al.	1997	2	45%	600	25	—	—	—	0.66	N	H	E	JPN
Bates	1995	1	37%	—	—	—	—	24	0.93	Y	C	E	GBR
Bates	1995	1	36%	—	—	—	—	24	0.96	Y	C	E	GBR
Cottrell et al.	2003	3	36%	100	30	77%	59%	23	0.90	Y	H	E	AUS
Damen and Faaij	2003	1	42%	600	—	—	60%	23	0.89	Y	C	E	NLD
Dolan	2007	1	—	841	30	60%	—	—	1.3	Y	C	E	USA
Dones et al.	1999	1	—	—	—	—	—	—	0.66	Y	H	E	CHE
Dones et al.	1999	3	—	—	—	—	—	—	0.68	Y	H	E	CHE
Dones et al.	2004	1	—	600	—	—	—	23	0.92	Y	C	E	CHN
Dones et al.	2004	1	—	300	—	—	—	23	1.0	Y	C	E	CHN
Dones et al.	2004	1	—	—	—	—	—	—	1.1	Y	C	E	CHN
Dones et al.	2004	1	—	125	—	—	—	23	1.1	Y	C	E	CHN
Dones et al.	2004	1	—	100	—	—	—	23	1.1	Y	C	E	CHN
Dones et al.	2004	1	—	210	—	—	—	23	1.1	Y	C	E	CHN
Dones et al.	2004	1	—	<100	—	—	—	23	1.4	Y	C	E	CHN
Dones et al.	2004	1	—	<100	—	—	—	23	1.6	Y	C	E	CHN
Dones et al.	2004	2	—	500	—	—	—	23	0.74	Y	F	T	CHN
Dones et al.	2004	3	—	300	—	—	—	23	0.94	Y	F	T	CHN
Dones et al.	2004	4	—	600	—	—	—	23	0.93	Y	F	T	CHN
Dones et al.	2007	1	42%	—	—	—	—	23	0.81	Y	C	E	NDL
Dones et al.	2007	1	40%	—	—	—	—	22	0.84	Y	C	E	AUT
Dones et al.	2007	1	38%	—	—	—	—	22	0.87	Y	C	E	SVK
Dones et al.	2007	1	38%	—	—	—	—	24	0.90	Y	C	E	PRT
Dones et al.	2007	1	37%	—	—	—	—	23	0.91	Y	C	E	ITA
Dones et al.	2007	1	36%	—	—	—	—	24	0.92	Y	C	E	DEU
Dones et al.	2007	1	36%	—	—	—	—	24	0.93	Y	C	E	BEL
Dones et al.	2007	1	36%	—	—	—	—	22	0.94	Y	C	E	HRV
Dones et al.	2007	1	35%	—	—	—	—	23	0.95	Y	C	E	NLD
Dones et al.	2007	1	36%	—	—	—	—	24	0.95	Y	C	E	FRA
Dones et al.	2007	1	36%	—	—	—	—	24	0.97	Y	C	E	ESP
Dones et al.	2007	1	33%	—	—	—	—	22	1.0	Y	C	E	POL
Dones et al.	2007	1	37%	—	—	—	—	12	1.0	Y	C	E	AUT
Dones et al.	2007	1	36%	—	—	—	—	11	1.1	Y	C	E	ESP
Dones et al.	2007	1	35%	—	—	—	—	8.3	1.1	Y	C	E	POL
Dones et al.	2007	1	33%	—	—	—	—	11	1.1	Y	C	E	CZE
Dones et al.	2007	1	29%	—	—	—	—	22	1.1	Y	C	E	CZE
Dones et al.	2007	1	30%	—	—	—	—	10	1.1	Y	C	E	BIH
Dones et al.	2007	1	32%	—	—	—	—	9.9	1.2	Y	C	E	SVN
Dones et al.	2007	1	33%	1,179	—	—	—	8.7	1.2	Y	C	E	DEU
Dones et al.	2007	1	32%	—	—	—	—	7.5	1.2	Y	C	E	MKD
Dones et al.	2007	1	35%	—	—	—	—	5.2	1.3	Y	C	E	GRC
Dones et al.	2007	1	30%	—	—	—	—	7.9	1.3	Y	C	E	YUG
Dones et al.	2007	1	28%	—	—	—	—	8.6	1.4	Y	C	E	HUN
Dones et al.	2007	1	28%	—	—	—	—	17	1.4	Y	C	E	FRA
Dones et al.	2007	1	23%	—	—	—	—	10	1.64	Y	C	E	SVK
Dones et al.	2008	2	45%	450	—	—	—	26	0.75	Y	F	T	EUR
Dones et al.	2008	2	45%	450	—	—	—	26	0.90	Y	F	T	EUR
Dones et al.	2008	4	43%	950	—	—	—	8.8	0.92	Y	F	T	EUR
DynCorp	1995	1	35%	500	30	75%	48%	18	1.1	Y	C	E	USA
EC	1995	1	39%	1,710	40	76%	60%	23	0.85	Y	C	E	EUR
EC	1995	1	39%	1,710	40	76%	60%	23	0.85	Y	C	E	EUR
EC	1995	1	39%	627	37	—	60%	23	0.90	Y	C	E	EUR
EC	1995	1	36%	589	35	—	—	8.5	1.1	Y	C	E	EUR
EC	1995	2	45%	1,710	40	76%	60%	23	0.75	Y	C	E	EUR
EC	1999	3	45%	1,710	40	76%	60%	23	0.73	Y	C	E	EUR

(*continued*)

Table 1 *Continued*

Author	*Pub. Year*	*Tech.*	*Eff. (%)*	*Cap. (MW)*	*Life (years)*	*C.F. (%)*	*Coal Carbon (% C)*	*Coal LHV (MJ/kg)*	*CEF (kg CO_2/ kWh)*	*Coal Meth. Inc.?*	*Temp Vint.*	*Data Type*	*Study Loc.*
EC	1999	3	45%	1,710	40	76%	60%	23	0.73	Y	C	E	EUR
EC	1999	3	43%	1,710	40	76%	60%	23	0.77	Y	C	E	EUR
EC	1999	3	40%	1,710	40	76%	60%	23	0.83	Y	C	E	EUR
EC	1999	1	38%	274	30	—	—	29	0.89	Y	C	E	BEL
EC	1999	1	44%	600	25	—	—	—	0.90	Y	C	E	NLD
EC	1999	1	38%	600	—	—	—	—	0.90	Y	C	E	FRA
EC	1999	1	37%	266	30	—	—	29	0.92	Y	C	E	BEL
EC	1999	1	33%	1,050	—	82%	46%	18	1.0	Y	C	E	ESP
Fiaschi and Lombardi	2002	2	46%	344	15	—	77%	—	0.73	Y	H	T	ITA
Friedrich and Marheineke	1994	1	38%	689	35	—	—	—	0.90	Y	C	E	DEU
Friedrich and Marheineke	1994	1	36%	624	35	—	—	—	1.1	Y	C	E	DEU
Froese et al.	2010	3	36%	600	—	95%	—	19	1.0	Y	C	E	USA
Gorokhov et al.	2000	2	41%	382	30	70%	—	24	0.75	Y	C	E	USA
Hartmann and Kaltschmitt	1999	1	43%	509	30	—	—	—	0.83	Y	C	E	DEU
Heller et al.	2004	1	34%	96	—	88%	76%	31	0.93	Y	C	E	USA
Hondo	2005	1	40%	1,000	30	70%	—	—	0.89	Y	C	E	JPN
Koornneef et al.	2008	1	35%	460	30	—	—	—	0.98	Y	C	E	NLD
Koornneef et al.	2008	4	46%	600	30	—	—	—	0.75	Y	H	T	NLD
Kreith et al.	1990	3	—	—	30	—	—	—	1.0	N	C	E	USA
Krewitt et al.	1997	1	43%	652	35	—	—	29	0.78	Y	C	E	DEU
Krewitt et al.	1997	1	40%	888	35	—	—	8.5	1.0	Y	C	E	DEU
Lee et al.	2004	1	39%	—	—	—	—	33	0.95	N	C	E	KOR
Lee et al.	2004	1	34%	—	—	—	—	21	1.1	N	C	E	KOR
Lenzen et al.	2006	1	—	1,000	35	90%	—	—	0.80	Y	H	E	AUS
Lenzen et al.	2006	1	39%	—	—	—	—	—	0.88	Y	F	E	AUS
Lenzen et al.	2006	1	38%	1,000	30	80%	84%	23	0.90	Y	H	E	AUS
Lenzen et al.	2006	1	32%	—	35	90%	—	—	0.98	Y	H	E	AUS
Lenzen et al.	2006	1	—	1,000	25	70%	—	—	1.1	Y	H	E	AUS
Lenzen et al.	2006	1	31%	—	30	80%	26%	—	1.1	Y	H	E	AUS
Lenzen et al.	2006	1	28%	—	25	70%	—	—	1.5	Y	H	E	AUS
Lenzen et al.	2006	4	45%	—	—	—	—	—	0.69	Y	H	E	AUS
Lenzen et al.	2006	4	42%	—	—	—	—	—	0.76	Y	H	E	AUS
Lenzen et al.	2006	4	41%	—	—	—	—	—	0.76	Y	H	E	AUS
Lenzen et al.	2006	4	41%	—	—	—	—	—	0.83	Y	H	E	AUS
Lenzen et al.	2006	4	40%	—	—	—	—	—	0.94	Y	H	E	AUS
Markewitz et al.	2009	1	46%	—	—	—	—	30	0.71	Y	H	T	DEU
Markewitz et al.	2009	1	43%	—	—	—	—	30	0.76	Y	C	E	DEU
Markewitz et al.	2009	1	45%	—	—	—	—	11	0.78	Y	H	T	DEU
Markewitz et al.	2009	1	39%	—	—	—	—	30	0.83	Y	C	E	DEU
Markewitz et al.	2009	1	41%	—	—	—	—	11	0.85	Y	C	E	DEU
Markewitz et al.	2009	1	36%	—	—	—	—	11	0.97	Y	C	E	DEU
Markewitz et al.	2009	4	49%	—	—	—	—	30	0.66	Y	F	T	DEU
Markewitz et al.	2009	4	48%	—	—	—	—	11	0.73	Y	F	T	DEU
Martin	1997	1	—	—	—	—	—	—	1.1	Y	C	E	USA
May and Brennan	2003	1	33%	—	—	—	59%	—	0.98	Y	H	E	AUS
May and Brennan	2003	1	33%	—	—	—	59%	—	1.0	Y	H	E	AUS
May and Brennan	2003	1	27%	—	—	—	25%	—	1.2	Y	H	E	AUS
May and Brennan	2003	2	51%	—	—	—	59%	—	0.64	Y	H	E	AUS
May and Brennan	2003	2	48%	—	—	—	25%	—	0.68	Y	H	E	AUS
May and Brennan	2003	2	51%	—	—	—	59%	—	0.71	Y	H	E	AUS
Meier et al.	2005	1	—	—	—	—	—	—	0.96	Y	H	T	USA
Meier et al.	2005	1	—	—	—	—	—	—	0.99	Y	H	T	USA
Meridian	1989	1	—	500	30	—	52%	—	1.1	N	C	E	USA
Meridian	1989	2	38%	945	30	—	52%	—	0.82	N	C	E	USA
Meridian	1989	3	—	500	30	—	52%	—	1.1	N	C	E	USA
NETL	2010a	1	37%	434	30	0.85	64%	26	1.0	Y	C	E	USA

(*continued*)

Table 1 *Continued*

Author	*Pub. Year*	*Tech.*	*Eff. (%)*	*Cap. (MW)*	*Life (years)*	*C.F. (%)*	*Coal Carbon (% C)*	*Coal LHV (MJ/kg)*	*CEF (kg CO_2/ kWh)*	*Coal Meth. Inc.?*	*Temp Vint.*	*Data Type*	*Study Loc.*
NETL	2010b	2	40%	622	30	0.80	64%	26	0.84	Y	H	E	USA
NETL	2010c	4	41%	550	30	0.85	64%	26	0.86	Y	H	E	USA
Odeh and Cockerill	2008a	1	35%	660	40	80%	60%	25	0.88	Y	C	E	GBR
Odeh and Cockerill	2008b	1	35%	475	—	—	60%	25	0.72	Y	C	E	GBR
Odeh and Cockerill	2008b	2	37%	500	—	—	60%	25	0.69	Y	C	E	GBR
Odeh and Cockerill	2008b	4	40%	453	—	—	60%	25	0.64	Y	C	E	GBR
ORNL	1994	1	35%	500	40	75%	74%	28	1.0	N	C	E	USA
ORNL	1994	1	35%	500	40	75%	55%	21	1.1	N	C	E	USA
ORNL	1994	4	—	—	—	—	—	—	0.75	N	C	E	USA
Pacca	2003	1	—	1,000	30	—	—	—	0.68	Y	H	E	USA
Peiu	2007	1	—	—	—	—	—	—	1.5	Y	C	E	ROM
Ruether et al.	2004	2	42%	543	20	85%	—	24	0.80	Y	C	E	USA
San Martin	1989	1	—	500	30	—	—	0	0.96	N	C	E	USA
San Martin	1989	2	—	945	30	—	—	—	0.75	N	C	E	USA
San Martin	1989	3	—	500	30	—	—	—	0.96	N	C	E	USA
Schreiber et al.	2009	4	49%	697	—	—	—	31	0.66	Y	F	T	DEU
Schreiber et al.	2009	4	46%	552	—	—	—	31	0.71	Y	F	T	DEU
Schreiber et al.	2009	4	43%	500	—	—	—	31	0.77	Y	C	E	DEU
SECDA	1994	1	33%	272	30	80%	40%	14	1.1	Y	C	E	CAN
SECDA	1994	1	33%	270	30	80%	40%	14	1.1	Y	C	E	CAN
SECDA	1994	1	33%	270	30	80%	34%	12	1.1	Y	C	E	CAN
SECDA	1994	1	29%	131	20	75%	40%	14	1.3	Y	C	E	CAN
SECDA	1994	2	38%	262	30	80%	40%	14	1.0	Y	C	E	CAN
SECDA	1994	3	33%	138	30	80%	40%	14	1.1	Y	C	E	CAN
SENES	2005	2	35%	262	—	—	—	27	0.75	Y	H	E	CAN
Shukla and Mahapatra	2007	1	—	—	—	—	—	—	1.3	Y	C	E	IND
Spath et al.	1999	1	42%	404	—	60%	70%	25	0.72	Y	C	E	USA
Spath et al.	1999	1	35%	425	—	60%	70%	25	0.89	Y	C	E	USA
Spath et al.	1999	1	32%	360	—	60%	70%	25	0.97	Y	C	E	USA
Spath and Mann	2004	1	—	600	—	—	—	—	0.80	Y	C	E	USA
Styles and Jones	2007	1	—	—	—	—	—	28	0.96	Y	C	E	IRL
Uchiyama	1996	1	41%	1,000	30	75%	—	—	0.90	Y	C	E	JPN
Uchiyama	1996	2	47%	1,000	30	75%	—	—	0.78	Y	F	T	JPN
Uchiyama	1996	4	45%	1,000	30	75%	—	—	0.81	Y	F	T	JPN
White	1998	1	32%	1,000	30	—	—	23	0.96	N	C	E	USA
Wibberley et al.	2000	1	38%	2,640	30	70%	59%	23	0.90	Y	C	E	AUS
Wibberley et al.	2000	2	46%	1,000	30	70%	59%	23	0.74	Y	H	T	AUS
Wibberley et al.	2000	3	44%	1,000	30	70%	59%	23	0.77	Y	H	T	AUS
Wibberley et al.	2000	4	42%	2,641	30	70%	59%	23	0.82	Y	H	E	AUS
Wibberley	2001	1	37%	4,117	—	—	51%	18	0.97	Y	H	E	ZAF
Wibberley	2001	1	38%	3,708	—	—	41%	15	0.99	Y	C	E	ZAF
Wibberley	2001	1	37%	4,117	—	—	51%	18	1.0	Y	C	E	ZAF
Wibberley	2001	1	37%	2,000	30	—	25%	8.4	1.1	Y	C	E	AUS
Wibberley	2001	3	44%	360	30	70%	71%	26	0.83	Y	C	E	JPN
Wibberley	2001	4	43%	1,000	30	—	65%	22	0.87	Y	C	E	JPN
Wibberley	2001	4	38%	3,960	30	—	36%	13	0.93	Y	H	E	IND
Wibberley	2001	4	40%	1,000	30	—	65%	22	0.94	Y	C	E	JPN
Zerlia	2003	4	44%	—	—	—	—	—	0.78	Y	H	E	ITA
Zerlia	2003	4	44%	—	—	—	—	—	0.78	Y	H	E	ITA
Zhang et al.	2007	1	35%	—	—	—	—	29	1.1	Y	C	E	CAN
Zhang et al.	2007	1	34%	—	—	—	—	13	1.3	Y	C	E	CAN
Zhang et al.	2010	1	35%	3,920	—	55%	—	21	0.94	Y	C	E	CAN
Zhang et al.	2010	1	33%	215	—	34%	—	15	1.2	Y	C	E	CAN

Note: Pub. Year = year of publication for the given reference; Tech. = technology type (1 = subcritical, 2 = integrated gasification combined cycle, 3 = fluidized bed, 4 = supercritical); Eff. = thermal efficiency; Cap. = capacity; Life = analysis lifetime of the life cycle assessment; C.F. = capacity factor; Coal Carbon = dry-weight percent of coal carbon content; Coal LHV = lower heating value, including LHVs reported directly in references and LHVs calculated from the conversion of higher heating values that were reported in references; CEF = combustion emission factor; Coal Meth. Inc.? = coal mine methane included?; Temp. Vint. = temporal vintage (C = existing technology case study, H = existing technology hypothetical study, F = future technology); Data type: E = primarily empirical data, T = primarily theoretical data; Study Loc. = primary country or location for the study: EUR = Europe, NDL = NORDEL countries (Denmark, Finland, Sweden, Norway), other country codes are based on United Nations three-letter codes (United Nations 2010); "—" indicates no value reported for that parameter.

Harmonization Approach

For the LCA Harmonization Project as a whole, two levels of harmonization were devised. The more resource-intensive level was envisioned as a process similar to that employed by Farrell and colleagues (2006) to harmonize the results of LCAs of ethanol. In that process, a subset of the available literature estimates of life cycle GHG emissions was carefully disaggregated. This process produced a detailed meta-model, based on factors such as adjusted parameter estimates, realigned system boundaries within each life cycle phase, and a review of all data sources. The less-intensive approach could harmonize a larger set of literature estimates of life cycle GHG emissions at a more gross level, for instance, by proportional adjustment of the estimate of life cycle GHG emissions to consistent values for several influential performance characteristics and, by addition or subtraction, to a common system boundary (at the level of a major life cycle stage). GWPs were also harmonized where possible. This less-intensive type of light harmonization was chosen for the coal-fired electricity generation analysis. The decision-making process for determining the level of harmonization is discussed in the supporting information on the Web.

In keeping with the less-intensive harmonization approach, estimates were not audited for accuracy; published GHG emission estimates were taken at face value and only converted to consistent units prior to being harmonized. Additionally, no exogenous assumptions were employed for harmonization. If a reference did not report the information required for harmonization, then that harmonization step was not applied to that specific published GHG emission estimate. Two cases of this sort arose during the analysis underlying this article: (1) GWP harmonization could not be applied to 57% of estimates because the mass emissions of each GHG were not separately reported; and (2) thermal efficiency was not reported for approximately 20% of estimates, resulting in this harmonization step not being applied to those estimates. In the first case, while variability in the harmonized results reported in this article is greater than if a fully consistent set of GWPs had been applied to all published results, the magnitude of increased variability is small because GWP was not found to be an influential harmonization step. In the second case, because the CEF inherently incorporates thermal efficiency (CEF is defined in the *Key Harmonization Parameters* section below), all estimates passing the second screen were in fact adjusted to technology-specific thermal efficiencies despite the inability to independently apply the thermal efficiency harmonization step to all estimates. Additional discussion of the potential impacts on study results from interpreting author assumptions and results is contained in the *Potential for Incorrect Interpretation of Study Methodologies or Assumptions* section of this article.

Statistical Assessment

Statistical assessments of variability and central tendency of the published and harmonized datasets are used to characterize the references that passed the second screening. Central tendency is reported using both the medians and arithmetic means (hereafter referred to as "mean") of the datasets. The variability of the datasets is also described using multiple parameters, including the standard deviation (SD), the range (maximum value minus minimum value), and the interquartile range (IQR) bounded by the 25th and 75th percentile values. (IQR magnitude is defined as the 75th percentile value minus the 25th percentile value.) The present discussion focuses on median and IQR, as these measures are less influenced by dataset outliers. For each harmonization step, changes in central tendency and variability are compared with published estimates to describe the impact of the harmonization step.

Key Harmonization Parameters

Table 1 reports important characteristics of the pool of estimates that underwent the harmonization process. Several references that passed the second screening provided more than one GHG emission estimate, based on either alternate scenarios or alternate technologies. Each individual scenario is listed as a separate row in table 1. The published GHG emission estimates for each scenario and the associated harmonized GHG emission estimates are provided in table S2 of the supporting information on the Web.

In addition to listing the references that underwent harmonization, table 1 also reports quantitative and qualitative descriptors of the evaluated technology and study characteristics. The study and technology descriptors include the following:

- Technology Type (Tech.): the coal combustion technology type.
- Capacity (Cap.): published electricity-generating capacity of the power plant (could be gross or net of loads at the plant itself). The value is provided for informational purposes only and not directly used in any harmonization step.
- Lifetime (Life): analysis lifetime for the LCA.
- Capacity Factor (C.F.): Published capacity factor values (can be gross or net of loads at the plant itself) indicating the ratio of electricity generated for a period of time to the potential electricity generated if the power plant operated at full power during the same period. The value is provided for informational purposes only and not directly used in any harmonization step.
- Coal Mine Methane Included (Coal Meth. Inc.?): identifies whether coal mine methane emissions were included in the study prior to harmonization.
- Temporal Vintage (Temp Vint.): describes the analyzed scenario as primarily a case study of an existing technology based on a previous performance period (C), a hypothetical study of an existing technology (H), or a study of a proposed future technology (F).
- Data Type: describes the data used in the analyzed scenario as primarily empirical (E) or theoretical (T).
- Study Location (Study Loc.): identifies the location (country) of the power plant considered in the study.

The key harmonization parameters include

- Thermal Efficiency (Eff.): the net electricity generated divided by fuel energy input on a lower heating value (LHV) basis. (This study consistently uses LHV to report the efficiency of the combustion systems and the energy content of the coal. This method removes the effects of the varying water contents of coal on the thermal efficiency analyses and more realistically estimates the thermal efficiency actually achieved, as heat released from condensing water vapor is rarely captured.)
- Coal Carbon Content (Coal Carbon): dry-weight percent carbon of the coal analyzed in the study.
- Coal Lower Heating Value (Coal LHV): the LHV of the coal analyzed in the study. For references in which the composition of the coal was provided, the higher heating value (HHV) was converted to LHV using the standard thermodynamic conversion in equation 1:

$$LHV = HHV - 0.212 * H - 0.0245 * M - 0.0008 * O, \quad (1)$$

where

LHV = lower heating value, megajoules per kilogram (MJ/kg),[2]

HHV = higher heating value (MJ/kg),

H = mass percent hydrogen (%),

M = mass percent moisture (%), and

O = mass percent oxygen (%).

- Combustion CEF: the coal CEF represents the mass of carbon dioxide (CO_2) in kilograms (kg) emitted per kilowatt-hour (kWh) of net electricity generated from a coal-fired power plant.[3] The CEF is a function of the thermal efficiency, coal carbon content, and coal LHV as shown in equation 2.

$$CEF = 99\% * \left(C * \left(\frac{44}{12}\right) \Big/ LHV * \eta * 0.278\right), \quad (2)$$

where

CEF = combustion CO_2 emission factor (kg CO_2/kWh);

99% = assumed percentage of fuel carbon converted to CO_2 during combustion (Lenzen et al. 2006);

C = coal carbon content (kg carbon/kg coal);

44/12 = ratio of molecular weights of CO_2 to carbon (kg CO_2/kg C);

LHV = lower heating value of the coal (megajoules of thermal energy in the fuel per kilogram of coal [MJ_{therm}]/kg coal);

η = plant's thermal efficiency (megajoules of electricity produced per megajoule of thermal energy in the fuel [MJ_{elec}]/MJ_{therm}); and

0.278 = conversion of electricity reported in kilowatt-hours per megajoules (kWh/MJ).

Harmonization parameters that were not explicitly listed in table 1 but were addressed in the study include GWPs, updated to Intergovernmental Panel on Climate Change (IPCC) 100-year values (IPCC 2007) where possible; conversion of the units of published results to grams of carbon dioxide equivalent per kilowatt-hour (g CO_2-eq/kWh); and system boundary harmonization to exclude GHG emissions related to delivering generated electricity to end users and transmission infrastructure (T&D losses), and to include GHG emissions from coal mine methane if omitted from the published study.[4] Details of the harmonization methods for each of the key parameters are provided in the supporting information on the Web.

Technology-Specific and Collective Harmonization

Each coal combustion technology was harmonized both independently and collectively with the other technologies. Technology-specific harmonization utilizes separate estimates of thermal efficiency and CEF for each of the four evaluated technologies drawn from the MIT study, *The Future of Coal* (MIT 2007). To select a modern thermal efficiency appropriate to each technology and to maintain consistency of source across evaluated technologies and harmonization parameters (i.e., CEF), benchmarks for each technology were gathered from the MIT study (MIT 2007). The MIT benchmarks represent technologies that currently are (or soon will be) commercially viable in the United States and that have all required emission-control technologies.

MIT modeled these systems using Carnegie Mellon University's (Pittsburgh, PA) Integrated Environmental Control Model, assuming the use of Illinois #6 bituminous coal for the subcritical, IGCC, and supercritical units, and lignite for the FB unit. Efficiency and CEF benchmarks were 35.4% and 932 g CO_2/kWh for subcritical, 39.8% and 832 g CO_2/kWh for IGCC, 38.3% and 1,034 g CO_2/kWh for FB, and 39.9% and 738 g CO_2/kWh for supercritical coal combustion. For comparison, when weighted by generation, the mean thermal efficiency of the evaluated eGRID 2007 data subset (U.S. Environmental Protection Agency 2009)–composed of 281 coal-fired power plants that did not use combined heat and power systems and generated more than 99% of their electricity from coal–was 33% with a CEF of 970 g CO_2/kWh. As expected, the modeled MIT thermal efficiencies for modern coal combustion technologies are greater than the eGRID weighted average because eGRID data represent actual operation and also include an older generation of coal power plants that primarily use subcritical pulverized combustion technology. In this way, the results of harmonization are modestly more applicable to plants designed and installed today or in the near future, but can also easily be altered to different efficiency and CEF assumptions.

An alternative approach to the technology-specific harmonization process, here called collective harmonization, was applied to define the central tendency and variability of life cycle GHG emission estimates for coal-combustion technologies considered collectively. Here we have harmonized all estimates to the same benchmark thermal efficiency and CEF values independent of technology type. Benchmarks for collective harmonization were the arithmetic mean thermal efficiency weighted by generation (33%) and CEF (970 g CO_2/kWh) values derived from the subset of eGRID 2007 data described previously (U.S.

Environmental Protection Agency 2009). Table S3 in the supporting information on the Web reports the results of the collective harmonization process, with harmonization by all parameters resulting in a median of 1,030 g CO_2-eq/kWh (IQR = 1,000 − 1,090 g CO_2-eq/kWh) compared with the published median of 1,001 g CO_2-eq/kWh (IQR = 891 − 1,134 g CO_2-eq/kWh). The collective harmonization approach is designed to estimate a reasonable range of life cycle GHG emissions when even the coal combustion technology type is unknown. Alternative estimates based on collective harmonization can be easily achieved using different assumptions of thermal efficiency and coal quality (or CEF). Note that the emphasis of the remaining results and discussion in this article is placed on harmonization using technology-specific factors for thermal efficiency and CEF.

Results and Discussion

Summary of Published Results

The 53 references that passed the two-tiered literature screening provided 164 estimates of life cycle GHG emissions from subcritical, IGCC, FB, and supercritical coal electricity generation technologies. Table 2 summarizes the central tendencies and variability of the published results for all four analyzed technologies (both individually and across all technologies) along with changes resulting from each harmonization step using technology-specific harmonization factors. The range of published estimates across all four technologies was 675 to 1,689 g CO_2-eq/kWh, with a median of 1,001 g CO_2-eq/kWh and an IQR of 891 to 1,134 g CO_2-eq/kWh.

The results for system and technical harmonization are reported both independently and cumulatively to maximize transparency, enabling users to select which results are most applicable to their analytical needs. The "System – all parameters" column reports the results of applying all three system harmonization steps to the published values to show the central tendency and variability of life cycle GHG emission estimates from the analyzed studies using consistent system boundaries and metrics. The "Cumulative – all parameters" column reports the results from applying the harmonization steps in succession with the system harmonization applied first, to standardize the analysis boundary followed by the application of technical harmonization to define the central tendency and variability of life cycle GHG emissions for each technology under specified operating conditions. To further enhance transparency, the step-by-step harmonization results for every published estimate of life cycle GHG emissions included in the final analysis are reported in table S2 in the supporting information on the Web.

Subcritical coal generation had the greatest number of GHG emission estimates passing the screening process (108), with a median and IQR for the published dataset of 1,060 g CO_2/kWh and 980 to 1,196 g CO_2/kWh, respectively. IGCC and supercritical coal combustion had fewer estimates than subcritical combustion (19 and 23, respectively), as well as reduced median values and smaller IQR magnitudes (see table 2). FB combustion had the fewest published data points passing screens (14). As discussed in the following sections, the harmonization process was most successful in reducing the variability of estimates for subcritical, supercritical, and IGCC coal combustion technologies, with the limited dataset for FB combustion exhibiting less response to the applied harmonization steps.

Figure 2(a) plots the published estimates in rank order from least to greatest life cycle GHG emissions. Variability in published estimates stems from multiple sources, including the five factors listed below. Each factor was identified for system (the first three) or technical (the last two) harmonization:

- use of GWPs other than IPCC 2007 100-year values (result of harmonization shown in figure 2(b)).
- system boundaries that extended beyond the generation of a kilowatt-hour of electricity to include T&D losses (figure 2(c)).
- inclusion or exclusion of coal mine methane emissions (figure 2(d)).
- assumed thermal efficiency of the power plant, partially based on technology selection (figure 2(e)).
- combustion CEF as a function of quality of the coal and thermal efficiency of combustion (figure 2(f)).

These five factors were addressed in the individual harmonization steps applied in the present study.

Contribution of Individual Greenhouse Gases

As the coal-fired electricity generation LCA literature consistently reported the global warming impacts of only direct GHG emissions, the present study did not evaluate the indirect GWP of air emissions such as nitrogen oxides and particulate matter. The reported direct life cycle GHG emissions of coal-fired electricity were dominated by CO_2, with methane (CH_4) and nitrous oxide (N_2O) making lesser contributions to GWP-weighted GHG emissions; their mean contribution estimates were approximately 5% and <1%, respectively. Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride mass emissions do not contribute significantly to GWP-weighted life cycle GHG emissions. See the supporting information on the Web for additional discussion regarding the relative contributions of CO_2, CH_4, and N_2O to life cycle GHG emissions.

Harmonized Results

Figure 2(a)–(h) displays the impacts of the harmonization steps, starting with published estimates in 2(a) and then reporting each harmonization step applied independently, concluding with cumulative system harmonization in 2(g) and cumulative harmonization by all parameters (system then technical) in 2(h). The figure displays results for all of the evaluated technologies, with the thermal efficiency, CEF, and cumulative harmonization steps using technology-specific harmonization factors. Harmonization by CEF incorporates the impacts of variations in thermal efficiency. To avoid double-counting, CEF is used in lieu of thermal efficiency during cumulative harmonization. The original rank order for the published study results is

Table 2 Changes to measures of central tendency and variability from application of individual harmonization steps and from the cumulative application of all harmonization parameters (all values reported in grams of carbon dioxide equivalent per kilowatt-hour [g CO_2-eq/kWh]).

		Harmonization Steps							
Technology	*Metric*	*Published*	*GWP*	*T&D loss*	*Coal mine methane*	*Thermal efficiency*	*Combustion CO_2 emission factor*	*System – all parameters*	*Cumulative – all parameters*
All technologies	Mean	1,026	1,030	1,020	1,030	1,040	980	1,020	980
	Std dev	199	200	200	200	150	120	200	120
	Minimum	675	670	660	670	710	740	660	730
	25th percentile	891	890	870	890	950	940	870	930
	Median	1,001	1,000	990	1,010	1,040	980	1,010	980
	75th percentile	1,134	1,130	1,110	1,130	1,120	1,050	1,120	1,050
	Maximum	1,689	1,690	1,690	1,690	1,690	1,370	1,690	1,370
	IQR magnitude	243	240	240	240	170	110	250	110
	Range	1,014	1,010	1,030	1,010	980	630	1,030	640
	Change in mean	—	<−5%	<−5%	<5%	<5%	<−5%	<−5%	<−5%
	Change in median	—	<5%	<−5%	<5%	<5%%	<−5%	<5%	<−5%
	Change in std dev	—	<−5%	<−5%	<−5%	−23%	−41%	<−5%	−40%
	Change in IQR	—	<5%	<−5%	<−5%	−31%	−56%	<5%	−53%
	Change in range	—	<5%	<5%	<5%	−<5%	−38%	<5%	−37%
	Estimates	164	71	164	164	133	164	164	164
	References	53	19	53	53	38	53	53	53
Subcritical	Mean	1,100	1,100	1,090	1,100	1,100	1,010	1,100	1,010
	Std dev	191	190	190	190	150	70	190	60
	Minimum	714	710	710	710	710	930	710	880
	25th percentile	980	980	980	980	1,000	960	980	960
	Median	1,060	1,060	1,060	1,080	1,090	980	1,070	990
	75th percentile	1,196	1,190	1,190	1,200	1,170	1,050	1,190	1,050
	Maximum	1,689	1,690	1,690	1,690	1,690	1,340	1,690	1,270
	IQR magnitude	216	210	210	220	170	90	210	90
	Range	975	980	980	980	980	400	980	390
	Change in mean	—	<−5%	<−5%	<5%	<−5%	−8%	<−5%	−8%
	Change in median	—	<5%	<−5%	<5%	<−5%	−7%	<5%	−7%
	Change in std dev	—	<−5%	<−5%	<−5%	<−5%	−65%	<−5%	−66%
	Change in IQR	—	<−5%	<−5%	<5%	−20%	−61%	<−5%	−60%
	Change in range	—	<5%	<5%	<5%	<5%	−59%	<5%	−59%
	Estimates	108	54	108	108	86	108	108	108
	References	40	16	40	40	27	40	40	
IGCC	Mean	840	840	830	850	900	920	840	920
	Std dev	105	110	110	100	90	70	100	70
	Minimum	675	680	660	680	750	830	660	840
	25th percentile	759	760	760	790	830	860	790	870
	Median	838	840	840	840	890	910	840	900
	75th percentile	888	890	860	900	950	930	870	940
	Maximum	1,130	1,130	1,130	1,130	1,080	1,080	1,130	1,080
	IQR magnitude	129	130	100	110	120	70	80	80
	Range	456	460	470	460	330	250	470	240
	Change in mean	—	<5%	< −5%	<5%	8%	9%	<5%	10%
	Change in median	—	<5%	<5%	<5%	6%	9%	<5%	8%
	Change in std dev	—	<5%	<5%	< −5%	−10%	−32%	<−5%	−32%
	Change in IQR	—	<5%	−20%	−17%	−9%	−46%	−38%	−41%
	Change in range	—	<5%	<5%	<5%	−27%	−46%	<5%	−47%
	Estimates	19	8	19	19	17	19	19	19
	References	16	4	16	16	14	16	16	16
Fluidized Bed	Mean	987	990	990	1,000	1,020	1,170	1,000	1,180
	Std dev	122	120	120	130	110	130	130	120
	Minimum	771	770	770	770	770	1040	770	1040

(*continued*)

Table 2 *Continued*

Technology	Metric	Published	GWP	T&D loss	Coal mine methane	Thermal efficiency	Combustion CO_2 emission factor	System – all parameters	Cumulative – all parameters
		Harmonization Steps							
	25th percentile	960	960	960	960	960	1,060	960	1,100
	Median	993	990	990	1,020	1,050	1,130	1,020	1,140
	75th percentile	1,053	1,050	1,050	1,080	1,110	1,300	1,080	1,300
	Maximum	1,249	1,250	1250	1,250	1,140	1,370	1,250	1,370
	IQR magnitude	93	90	90	110	150	230	110	200
	Range	478	480	480	480	370	330	480	330
	Change in mean	—	<5%	<5%	<5%	<5%	18%	<5%	20%
	Change in median	—	<5%	<5%	<5%	6%	14%	<5%	15%
	Change in std dev	—	<5%	<5%	5%	−11%	8%	5%	< −5%
	Change in IQR	—	<5%	<5%	21%	56%	150%	21%	110%
	Change in range	—	<5%	<5%	<5%	−23%	−31%	<5%	−32%
	Estimates	14	5	14	14	9	14	14	14
	References	10	2	10	10	5	10	10	
Supercritical	Mean	858	860	850	860	920	800	850	790
	Std dev	101	100	100	100	80	60	100	60
	Minimum	687	690	680	690	750	740	680	730
	25th percentile	781	780	750	800	880	760	780	750
	Median	863	860	840	860	920	770	840	770
	75th percentile	922	910	910	920	990	830	910	830
	Maximum	1,059	1,060	1,060	1,060	1,060	1,010	1,060	1,010
	IQR magnitude	141	130	160	120	110	70	130	80
	Range	372	370	380	370	310	270	380	280
	Change in mean	—	<5%	< −5%	<5%	7%	−7%	<−5%	−8%
	Change in median	—	<5%	< −5%	<5%	7%	−11%	<−5%	−11%
	Change in std dev	—	<5%	< −5%	< −5%	−19%	−42%	−5%	−37%
	Change in IQR	—	−9%	12%	−10%	−22%	−52%	−6%	−42%
	Change in range	—	<5%	<5%	<5%	−16%	−28%	<5%	−25%
	Estimates	23	4	23	23	21	23	23	23
	References	13	2	13	13	11	13	13	13

Notes: (1) Harmonized values are rounded to two significant digits if less than 1,000 and three significant digits if equal to or greater than 1,000. (2) Percentages are rounded to the nearest whole number as an indication of uncertainty. (3) The cutoff for significance for change in measures of central tendency and variability is set at 5%. (4) Percent change for harmonized values compared with published estimates calculated prior to rounding and then reported to the nearest whole percent. (5) "Estimates" and "References" indicate the number of independent studies and published GHG emission estimates that were harmonized in each step (respectively). (6) The statistics reported for each step refer to the full population for that technology, including both harmonized and unharmonized estimates. (7) Harmonized estimates for thermal efficiency, combustion emission factor (CEF), and "Cumulative – all parameters" are calculated using technology-specific harmonization factors. (8) The "All technologies" technology category reports statistical results across all four evaluated technologies when technology-specific harmonization factors are used. (9) "System – all parameters" applies all system harmonization steps. (10) "Cumulative – all parameters" applies system harmonization followed by technical harmonization. (11) Refer to the *Limitations of the Analysis* section of the text for a discussion of reasons for interpreting the distributional statistics reported in this article with caution based on the characteristics of the pool of available studies and estimates. Std dev = standard deviation; IQR magnitude = interquartile range (75th–25th percentile); GWP = global warming potential; T&D = transmission and distribution.

maintained throughout each frame. Results of harmonization by each step are discussed in the following sections.

Table 2 summarizes the results of each harmonization step, including changes in central tendencies and variability of the datasets. Changes in dataset statistics are reported to the nearest percent as a sign of uncertainty, with the cutoff for significant change set at 5%. Decreases in IQR magnitude indicate effective harmonization in terms of a tightened range of life cycle GHG emission estimates from the evaluated technology. The IGCC, FB, and supercritical coal combustion were more prone to significant changes in central tendency and variability than was the subcritical dataset, due to relatively fewer independent GHG emission estimates in their datasets. Table S2 in the supporting information on the Web provides the numerical results of harmonization for each of the life cycle GHG estimates screened for harmonization.

Global Warming Potential

Dates of publication for the references analyzed in this study ranged from 1989 to 2010. Over that period, consensus GWPs reported by the IPCC for conversion of mass emissions of individual GHGs to CO_2 equivalents changed four times. The present study uses IPCC 2007 100-year GWPs, namely 25 for CH_4 and 298 for N_2O (IPCC 2007). This harmonization step updated published GHG emission estimates to IPCC 2007 100-year values for those studies in which alternate GWPs were used

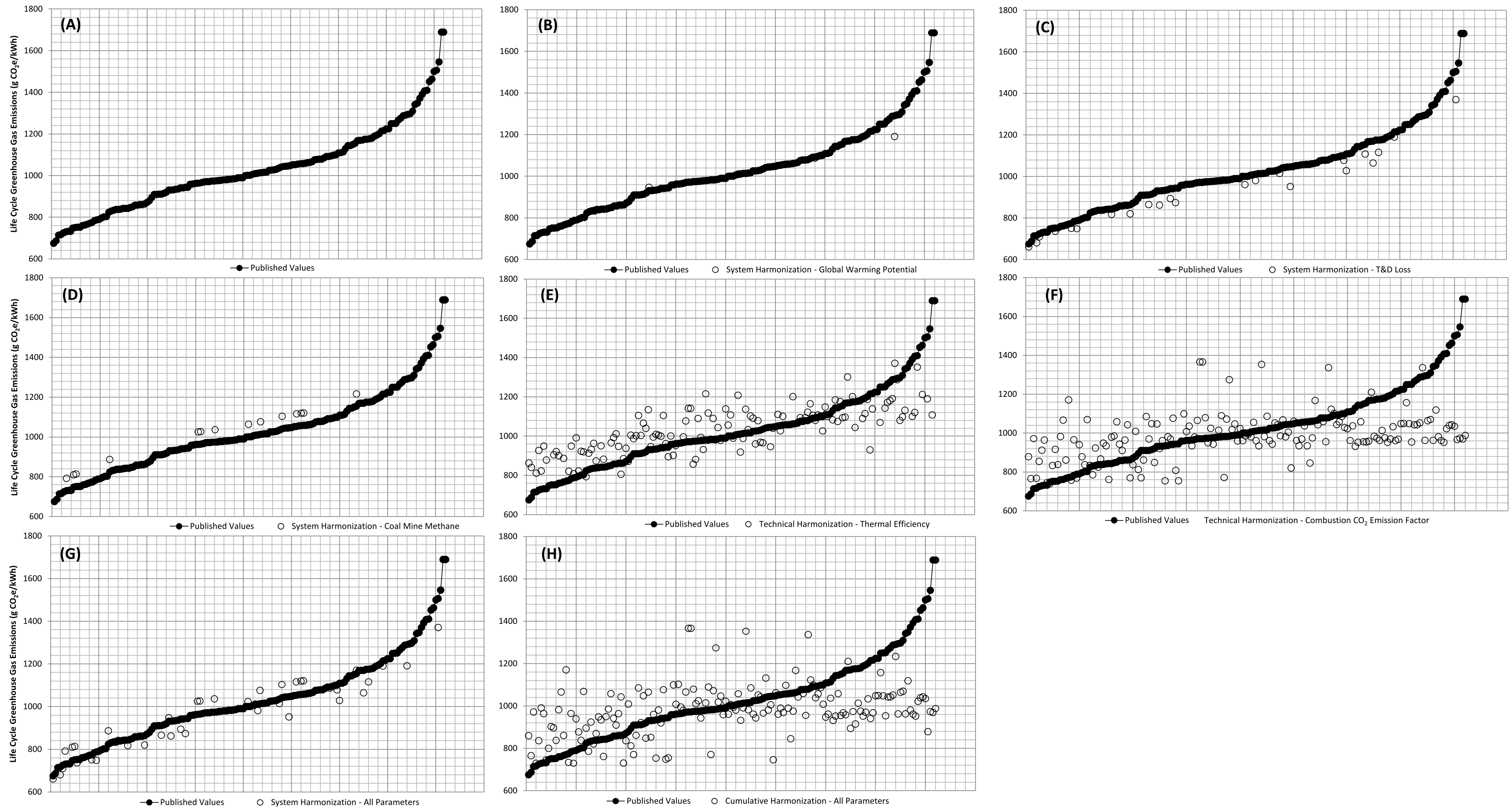

Figure 2 Rank-order estimates ($n = 164$, displayed least to greatest) of life cycle grams of carbon dioxide equivalent per kilowatt-hour (g CO_2-eq/kWh) for coal-fired electricity generation, drawn from literature that passed screenings for quality and relevance. Panel (A) reports only published data values. Panels (B) through (F) show the impact of independent application of harmonization steps (open circles) relative to published data (filled circles): (B) system harmonization by global warming potential (GWP); (C) system harmonization by transmission and distribution (T&D) loss; (D) system harmonization by coal mining methane; (E) technical harmonization by thermal efficiency; and (F) technical harmonization by combustion emission factor (CEF). Panel (G) shows the effect of applying all three system harmonization steps and panel (H) shows the cumulative effect of applying technical harmonization after system harmonization. For all of the evaluated technologies, the thermal efficiency, CEF, and cumulative harmonization steps use technology-specific harmonization factors. Numerical data associated with each point are displayed in table S2 of the supporting information on the Web. The y-axis reads 600 to 1,800 g CO_2-eq/kWh.

and sufficient detail was provided to identify emission rates of CH_4 and N_2O separately from CO_2 (figure 2(b)). Nineteen references with 71 GHG emission estimates (43% of those passing screens) provided sufficient disaggregated GHG emission data to harmonize for GWP. Changes to the dataset median from harmonization by GWP totaled less than 5% for all evaluated technologies, with supercritical combustion showing a reduction in IQR magnitude of approximately 9%.

Transmission and Distribution Loss

The T&D loss harmonization step aligned system boundaries of the studies by removing the impact of T&D losses on published life cycle GHG emission estimates (figure 2(c)). Six studies (Lee et al. 2004; Lenzen et al. 2006; May and Brennan 2003; NETL 2010a, 2010b, 2010c) included T&D losses in their published estimates (21 estimates). The remainder of the studies set system boundaries at the generation of electricity at the power plant. Eliminating T&D loss had an impact of less than 5% on the median for all technologies, reduced the IQR magnitude for IGCC by 20%, and increased the IQR of supercritical combustion by 12%; small sample sizes amplified the effect of eliminating T&D loss on the changes in IQR for those technologies. While not addressed in this study, if system boundaries were harmonized to include T&D losses, median estimates should increase by approximately 5% to 10%, but with an unknown impact on variability (dependent on differences in T&D loss assumptions for each reference). T&D losses vary considerably based on the region of delivery and the transmission capacity of the system at the time of generation, and they are challenging to apportion for any particular source of electricity (Weber et al. 2010). Therefore, to avoid an added factor of variability and uncertainty, this study elected to focus the GHG analysis on coal-fired electricity generation without the impacts of delivery to the end user, despite the intuitive appeal of incorporating GHG emissions associated with T&D losses.

Coal Mine Methane

The other primary difference in system boundary that was identified in the review of the published studies was whether coal mine CH_4 emissions were included (figure 2(d)). Fourteen GHG emission estimates (or 9% of those passing screens) were identified as not including coal mine methane emissions (see table 1). The harmonization process took a three-step approach to addressing this issue. First, the published GHG emission estimates for studies that did include coal mine methane (or stated that they did) were left unchanged, even if not reported separately. Second, an analysis of the published estimates from studies that disaggregated the contribution to life cycle GHG emissions from coal mine CH_4 (28 estimates from 17 studies) was conducted and yielded a median estimate of 63 g CO_2-eq/kWh (IQR = 54–73 g CO_2-eq/kWh) or approximately 6.3% of the median of the published life cycle GHG emissions across all four technologies. Lastly, the median estimate of 63 g CO_2-eq/kWh was added to the published GHG emission estimates drawn from those studies that did not explicitly include coal mine CH_4 emissions. Note that in order to keep system and technical harmonization separate, when the coal mine CH_4 harmonization step was considered cumulatively with that from thermal efficiency or CEF harmonization (and also "Cumulative – all parameters" harmonization), coal mine CH_4 harmonization was applied prior to scaling by efficiency. Alternately, if efficiency harmonization had been applied to coal mine CH_4 estimates prior to determining the value for addition, the median coal mine CH_4 emissions would have increased from 63 g CO_2-eq/kWh to 67 g CO_2-eq/kWh, but overall harmonization by all parameter results for median, mean, and IQR magnitude would have changed by less than 1%.

Adding 63 g CO_2-eq/kWh to the 14 estimates that previously had not included this factor increased their life cycle GHG emissions by 5.1% to 7.9%, with a median increase of 6.0% and an average increase of 6.3%. The range of relative contribution from the addition of coal mine CH_4 is consistent with the 63 g CO_2-eq/kWh, representing 6.3% of the median of the published life cycle GHG emissions across all four technologies. The IQR magnitude for IGCC and supercritical coal combustion technologies decreased by approximately 17% and 10%, respectively, by bringing lower-end published GHG emission estimates closer to the median of the dataset.

For the purposes of this analysis, a point estimate for coal mine GHG emissions was added to all studies that omitted that stage from their initial analyses. Based on the large range of coal mine CH_4 emissions for surface and underground coal mines, many plausible values could have been selected for this harmonization step. By separately reporting all harmonization steps for each analyzed estimate, other researchers can readily adapt these results to their selected coal mine CH_4 release conditions (see table S2 in the supporting information on the Web). In applying the results of this analysis to first-order estimates of life cycle GHG emissions for other coal-fired electricity generation projects, decision makers should pay special attention to coal mine CH_4 emissions from their project's source mines: these emissions have the potential to alter life cycle GHG emissions estimates significantly if the coal mine CH_4 emissions are expected to contribute more than approximately 5% to 8% of life cycle GHG emissions to the project on a gram CO_2 equivalent per kilowatt-hour basis. Refer to the section *Potential for Incorrect Interpretation of Study Methodologies or Assumptions* for a discussion of how the correct application of the coal mine CH_4 harmonization step is complicated by the level of reporting of assumptions and results in the pool of analyzed studies. See the section *Evaluation of the Effects of Future Coal Mining Trends* for additional discussion related to the potential impacts of coal mine techniques on life cycle GHG emissions.

Thermal Efficiency

Life cycle GHG emissions for coal combustion technologies are roughly inversely proportional to a power plant's thermal efficiency. To complete this harmonization step according to equation S1 in the supporting information on the Web, it was assumed that only GHG emissions related to the coal fuel cycle (including combustion) were impacted by a change in thermal efficiency, which regulates the amount of coal required to generate 1 kWh of electricity. Based on the analysis of GHG emissions disaggregated by life cycle stage for each technology type (table S1 in the supporting information on the Web), the assumed fraction of life cycle GHG emissions related to the fuel cycle, including combustion, for all evaluated technologies is 99%.

Table 2 shows the impact of the thermal efficiency harmonization step on summary statistics of life cycle GHG emission estimates for each technology. Thermal efficiency harmonization moderately impacted the medians of the datasets, with changes from published data of 3% to 7%. The IQR magnitudes for the published estimates of subcritical and supercritical coal combustion, however, were reduced by 20% and 22%, respectively.

Combustion Carbon Dioxide Emission Factor

The final harmonization step went beyond the thermal efficiency of the power plant to harmonize the published GHG emission estimates by the CEF (equation 2; figure 2(f)). Non-CO_2 GHGs were excluded from the CEF based on a lack of data. On average, however, CO_2 accounts for more than 98% of total GHG emissions from coal combustion, with CH_4 and N_2O collectively estimated to contribute less than 2% of total CO_2 equivalent emissions from coal combustion in the evaluated references (Dones et al. 2007; Krewitt et al. 1997; Zhang et al. 2010). This suggests only minor underestimation of GHG emissions by excluding non-CO_2 GHGs. Harmonizing by CEF adjusts GHG emissions throughout the coal fuel cycle, as the thermal efficiency and coal heating value components of CEF dictate the amount of coal that must be mined and transported upstream of combustion.

CEFs were extractable from all 164 scenarios analyzed in the present study, as the authors either directly reported the CEF, identified the percentage of total CO_2 emissions attributable to combustion, or listed sufficient details regarding the power plant's thermal efficiency and the quality of the coal to enable independent calculation of the CEF. This harmonization step normalized the CEF to technology-specific CEFs gathered from the MIT study (MIT 2007), namely 932 g CO_2/kWh for subcritical, 832 g CO_2/kWh for IGCC, 1,034 g CO_2/kWh for FB, and 738 g CO_2/kWh for supercritical coal combustion. Harmonization by CEF was the most effective individual step for reducing variability for subcritical, IGCC, and supercritical coal combustion, with reductions of 61%, 46%, and 52% in IQR magnitude, respectively. For FB combustion, CEF harmonization reduced the overall range of estimates by 32%, but the IQR increased by 110%. This opposing shift in overall range and IQR may be more an artifact of the small pool of FB estimates than an indication that FB combustion responds differently to harmonization than the other evaluated technologies.

System Harmonization – All Parameters

Figure 2(g) summarizes the impacts of applying system harmonization to adjust published estimates to consistent boundaries and metrics by harmonizing for GWP, T&D loss, and coal mine CH_4 emissions cumulatively. Once system harmonization is complete, the estimates can be properly compared on the same basis and technical harmonization can be applied. System harmonization had an impact of less than 5% on the median and mean of published results for all evaluated technologies, as reported in table 2.

Cumulative Harmonization – All Parameters

The system and technical harmonization steps previously described were cumulatively applied (figure 2(h)) in the following order: the GWPs were harmonized to IPCC 2007 100-year values, the system boundaries were then adjusted to exclude T&D losses and to include coal mine CH_4 emissions, then harmonization for CEFs (which inherently harmonizes thermal efficiency) was performed. Figure S1 in the supporting information on the Web provides a consolidated view of the process and shows on one plot the impact of each of the individual harmonization steps applied sequentially to the published estimates. Harmonizing the published estimates cumulatively by all of the harmonization parameters resulted in significant IQR reductions of 60%, 41%, and 42% for subcritical, IGCC, and supercritical combustion, respectively.

Published Versus Harmonized Results for the Evaluated Technologies

Figure 3 displays box plots for the published and harmonized (by all parameters) life cycle GHG emission estimates for each of the four individual technologies analyzed in the present study and for the full dataset encompassing all four technologies before and after the technology-specific harmonization. Numerical results are presented in Table 2. Prior to harmonization, the median and IQR of the published estimates (considering all four technologies) were 1,001 g CO_2-eq/kWh and 891 to 1,134 g CO_2-eq/kWh, respectively. After technology-specific harmonization, the dataset median across all four evaluated technologies decreased by approximately 2%, to 980 g CO_2-eq/kWh, and the IQR magnitude decreased by 53% with bounding values of 930 to 1,050 g CO_2-eq/kWh. In certain analytical and decision-making contexts, the results of harmonization could be used as reasonable estimates of life cycle GHG emissions, without requiring that a full LCA be conducted with each new project.

Using Results of Harmonization to Generate Project-Specific Estimates of Life Cycle GHG Emissions

Life cycle GHG emissions of a particular power plant depend on many factors and legitimately could differ from the generic estimates generated by the harmonization approach. In the context of both technology-specific and collective harmonization, the authors acknowledge that alternative thermal efficiency or CEF values could have legitimately been chosen from other national or international data sources as the basis for harmonization. By disaggregating all results by harmonization stage and clearly outlining assumptions and formulas used, other researchers can readily reproduce the results of this study to obtain a credible estimate of the life cycle GHG emissions

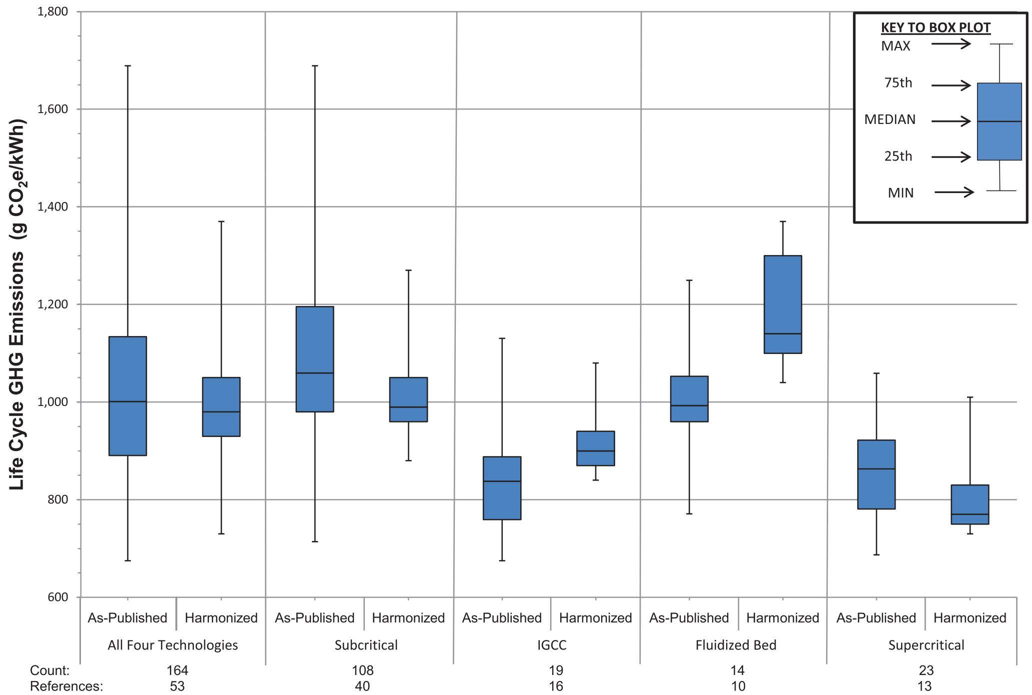

Figure 3 Box plots of published and harmonized estimates of life cycle greenhouse gas (GHG) emissions for coal-fired electricity generation considering all four evaluated technologies as a group and each evaluated technology independently using technology-specific harmonization factors for all analyses.

for a coal-fired electricity generation project by using equation 3. Adaptation can utilize project-specific, fleet, or any hypothetical set of operational conditions for the evaluated coal combustion technologies. Estimates can be further refined by incorporating project-specific information related to coal mine CH_4 emissions. Detailed information regarding other upstream and downstream life cycle stages, such as plant constructions and decommissions, are less critical to better defining the life cycle GHG emissions of a project than properly determining the plant's expected operational characteristics and the coal mine and coal quality associated with the project.

Equation 3 uses the principles of CEF harmonization to adjust the median harmonized estimate to project-specific conditions. It does this by harmonizing project GHG emissions that depend directly on the amount of coal burned, including coal mining, preparation, transport, and combustion. The fraction of life cycle GHG emissions modulated by the coal fuel cycle (including combustion) is assumed to be 99% for all technologies. IQR values can be adjusted similarly to provide a first-order estimate of a reasonable range of life cycle GHG emissions for project-specific conditions, with further customization possible if factors such as likely coal mine CH_4 emissions are known.

$$GHG_{pr} = FC * \frac{CEF_{h,t}}{CEF_{pr}} * GHG_{med,t} + (1 - FC) * GHG_{med,t}, \quad (3)$$

where

GHG_{pr} = estimated life cycle GHG emissions for the analyzed project, *pr* (g CO_2-eq/kWh);

FC = assumed fraction of life cycle GHG emissions modulated by the coal fuel cycle (default = 99%);

$CEF_{h,t}$ = harmonized CEF estimate used in the present study by technology, *t* (g CO_2/kWh);

CEF_{pr} = CEF calculated for the analyzed power plant project, *pr* (g CO_2/kWh); and

$GHG_{med,t}$ = median GHG emissions from table 2 for the proposed project technology, *t*, harmonized by all parameters (g CO_2-eq/kWh).

Limitations of the Analysis

This study is intended to explain and reduce the variability in existing estimates by identifying critical parameters that vary between studies, harmonizing them to allow for a consistent comparison of different studies' estimates, and achieving more robust estimates of variability and central tendency. There are several limitations to achieving these goals.

Parameters Not Harmonized

The analysis used only five parameters for harmonization based on data availability and the likelihood of significant impacts on published results: GWP, T&D losses, coal mine CH_4 emissions, thermal efficiency, and CEF. LCAs evaluate hundreds of parameters. Detailed harmonization of every parameter in every study is not possible; that level of detail is rarely reported and typically undesirable, as the necessary time and cost required to conduct such an analysis is not commensurate with the expected benefit of harmonizing all, or the majority, of parameters.

For upstream processes related to power plant construction and downstream processes related to waste disposal, mine rehabilitation, and power plant decommissioning, overall contributions to life cycle GHG emissions were less than 1%. Therefore harmonization by system boundary for upstream and downstream phases, or by parameters that only affect GHG emissions from those two phases, such as capacity factor and lifetime, were not considered important for the harmonization process of this study.

One parameter that was not harmonized due to lack of consistently available disaggregated data was GHG emissions associated with the transport of coal from the mine to the power plant. Every analyzed scenario included coal transport in its calculations, but the contribution of coal transport to life cycle GHG emissions was reported separately in less than 20% of the scenarios. When reported, its average contribution was 2% to 3% of life cycle GHG emissions, with the largest reported contribution for long-distance, transoceanic transport of coal, at approximately 8%. To harmonize on coal transport, more consistent reporting of coal transport GHG emissions would be required. This would enable addition or subtraction of GHG emissions based on the scenario's assumed transportation GHG emissions as compared with a baseline level. Nevertheless, omission of harmonization by this parameter should not change the overall conclusions of this analysis. However, when adapting the results of this analysis, users are cautioned to consider whether coal transport would likely contribute more than 5% of their project's life cycle GHG emissions based on expected transport distances and modes.

Potential for Incorrect Interpretation of Study Methods or Assumptions

Two additional limitations were imposed by the pool of published papers. First, incorrect assumptions about included or excluded life cycle stages or values of performance parameters could have resulted in the incorrect application of harmonization steps. Even after setting a minimum threshold for transparency, references varied greatly in their level of reporting of assumptions and results. Thus, despite careful reading of each reference, attempted correspondence with authors, and the researchers' decision not to employ any exogenous assumptions in the harmonization process, some judgments were still required. One example of where the researchers' judgment could have erred is in identifying a reference as having excluded coal mine CH_4 emissions when in fact it might have included those emissions. This circumstance could have resulted in the incorrect addition of 63 g CO_2-eq/kWh. Because coal mine CH_4 emissions were added to only 14 GHG estimates from 7 independent references, the potential effect of double-counted coal mine CH_4 emissions on overall study statistics should be minimal.

Another example of the adjustments required to ensure consistency is the conversion of thermal efficiencies reported in HHV to LHV (using equation 1) prior to the efficiency harmonization step. For studies that reported all information necessary to make the heating value adjustment, the average ratio of coal HHV to LHV was approximately 1.045. For two other studies that reported using HHV but did not provide enough data for conversion using equation 1 (Akai et al. 1997; Uchiyama 1996), reported HHV was converted to LHV using the 1.045 average ratio drawn from other studies. The average ratio was applied to only two references representing four GHG emission estimates; it is therefore unlikely that any uncertainty in estimating the LHV efficiency from the HHV efficiency significantly affected the overall results of the study.

Limitations Related to Statistical Population

Another limitation of the study presented here is that its population of studies is not necessarily representative of the technology as deployed, or of its potential. Although the most relevant, high-quality studies for each technology were selected, the studies reviewed might not cover all possible cases of manufacture, deployment, or use. Moreover, the estimates in this sample are not all statistically independent. The 164 independent estimates were generated by only 42 different first authors. As a result, estimates in the population of studies could cluster when author assumptions and biases are carried through serial publications by the same lead author, or where multiple GHG emission estimates from the same reference share common assumptions. Clustering could also occur when independent authors cite the same data sources or use the same professional life cycle inventory databases for their analyses. Because the population of GHG emission estimates does not constitute a true independent sample, the distributional statistics reported in this article should be interpreted with caution and should be viewed only as indicative of the true central tendency and variability for each technology. Also, reported changes in distributional statistics due to harmonization for the technologies other than subcritical pulverized coal should be interpreted with caution due to small sample sizes for GHG emissions for those technologies (less than 30). A potential topic for future research could be the statistical accounting for the multiple clustering mechanisms within the pool of estimates analyzed in the present study to better determine central tendency and variability.

Recommendations for Future Work

Alignment of Key Statistical Parameters with Operating Power Plants

A different direction for future harmonization studies would be to compare key parameters of the published datasets with coal power plants actually in operation, or those projected to be deployed, including both coal combustion emissions and associated impacts such as noncombustion power plant operation, coal transport, and coal mine CH_4 emissions. The life cycle GHG emissions of an existing or projected coal-fired power plant fleet could be estimated by weighting the results of this harmonization to match the generation profile and technology characteristics of the power plant fleet and mining methods being evaluated.

Evaluation of the Effects of Future Coal Mining Trends

Coal mining can have a significant impact on the life cycle GHG emissions of coal-fired electricity generation due to both coal mine CH_4 emissions and terrestrial carbon disturbance. These sources of GHG emissions should be considered when using the results of this analysis to estimate first-order life cycle GHG emissions for other coal-fired electricity generation projects. As noted in multiple studies, such as Spath and colleagues (1999) and Dones and colleagues (2007), underground hard coal mining tends to emit more CH_4 than both surface hard coal mining and lignite mining. As a result, shifts in the proportion of coal sourced from underground versus surface mining operations could affect the life cycle GHG emissions of coal-fired electricity generation projects, particularly because carbon capture and storage (CCS) removes greater percentages of the CO_2 emissions generated during combustion.

Coal sourced from underground mines, however, might not contribute more to a project's life cycle GHG emissions as compared with surface-mined coal if the release of GHG emissions from terrestrial carbon disturbance is confirmed. A recent study by Fox and Campbell (2010) suggests that terrestrial carbon disturbances from a mountaintop removal coal mine could be a significant source of CO_2 emissions for coal power generation projects using such coal. Fox and Campbell suggest that indirect carbon emissions from terrestrial soil and nonsoil carbon brought to the surface by mountaintop coal mines could reach 7% of life cycle GHG emissions for a conventional coal-fired power plant and up to 70% of life cycle GHG emissions for a power plant equipped with CCS. Further research is needed to confirm these findings and to estimate GHG emissions from surface coal mine operations besides mountaintop removal that disturb terrestrial carbon sinks. If Fox and Campbell's findings are confirmed, then the relative contribution of these indirect emissions to life cycle GHG emissions for power plants that rely on coal sourced from mountaintop removal or surface coal mines could be on a scale similar to coal mine CH_4 emissions for power plants that rely on coal from underground mines. Additional harmonization would be required to add GHG emissions from terrestrial carbon disturbance to the published values in the dataset (at least for those studies that assumed mountaintop removal as the coal-mining method), as no scenarios analyzed in this study explicitly included it.

Conclusions

Existing literature estimates, which vary from 675 to 1,689 g CO_2-eq/kWh, have led to confusion over life cycle GHG emissions from coal-fired electricity generation. By adjusting published estimates to common gross system boundaries and to consistent, technology-specific values for key input parameters, the meta-analytical process called harmonization clarifies the existing literature in ways useful for decision makers and analysts. Although the life cycle GHG emissions of a specific power plant depend on many factors and legitimately can differ from the generic estimates generated by the harmonization approach, given the tightness of the distribution of harmonized estimates across several key coal combustion technologies, for some purposes, first-order estimates of life cycle GHG emissions could be based on knowledge of the technology type, thermal efficiency, coal source, and CEF alone, without requiring full LCAs.

For the life cycle GHG emissions of coal-fired electricity generation, the harmonization process as employed here was found to be both relatively straightforward and effective. Approximately 99% of GHG emissions in the coal-generated electricity life cycle are directly related to the coal fuel cycle, including coal mining and processing, coal transport, and coal combustion at the power plant. As a result, parameters that influence the amount of coal burned per kilowatt-hour generated (thermal efficiency) together with the level of GHG emissions released during coal mining (coal mine CH_4) and the combustion of that coal (coal carbon content) are the most influential on life cycle GHG emissions.

Harmonizing the published life cycle GHG emission estimates for each coal technology by the technology-specific key harmonization parameters identified in the present study reduced the IQR magnitudes for subcritical, IGCC, and supercritical coal combustion by approximately 40% to 60%, without changing the central tendency by more than approximately 10% for any technology. For FB combustion, harmonization resulted in a 15% increase in the median, but a 32% decrease in the overall range of estimates despite an increase in the IQR. The relatively large shift in median and the opposing shifts in IQR and range for FB could be more an artifact of the small pool of estimates than an indication that the FB technology responds differently to harmonization than the other evaluated technologies. Prior to harmonization, the median and IQR of the published estimates across all technologies were 1,001 g CO_2-eq/kWh and 891 to 1,134 g CO_2-eq/kWh, respectively. After technology-specific harmonization, the dataset median decreased by approximately 2%, to 980 g CO_2-eq/kWh and the IQR magnitude decreased by 57% to bounding values of 930 to 1,050 g CO_2-eq/kWh. Although the results of this study were harmonized to U.S. operating power plant conditions, decision makers can readily adapt the results to obtain a credible estimate of the life cycle GHG emissions for electricity generated by any domestic or international coal-fired power plant project using the evaluated technologies by simply following the methods and equations reported in this article.

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Notes

1. Results from the whole LCA Harmonization project, including from this article, can be visualized and downloaded at http://openei.org/apps/LCA.
2. One megajoule (MJ) = 10^6 joules (J, SI) ≈ 239 kilocalories (kcal) ≈ 948 British thermal units (BTU). One kilogram (kg, SI) ≈ 2.204 pounds (lb).
3. One kilowatt-hour (kWh) ≈ 3.6×10^6 joules (J, SI) ≈ 3.412×10^3 British thermal units (BTU).
4. One gram (g) = 10^{-3} kilograms (kg, SI) ≈ 0.035 ounces (oz). Carbon dioxide equivalent (CO_2-eq) is a measure for describing the climate-forcing strength of a quantity of greenhouse gases using the functionally equivalent amount of carbon dioxide as the reference.

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Supporting Information

Additional supporting information may be found in the online version of this article.

Supporting Information S1: This supporting information provides the detailed methodology for the two-stage quantitative test developed to determine the appropriate level of harmonization for a given electricity generation technology analyzed by the LCA Harmonization Project led by the NREL. The full list of references reviewed for this harmonization analysis is also included.