CLIMATE LEADERS GREENHOUSE GAS INVENTORY PROTOCOL OFFSET PROJECT METHODOLOGY

for

Project Type: Commercial Boiler Efficiency

(Space and Hot Water Heating)

Climate Protection Partnerships Division/Climate Change Division

Office of Atmospheric Programs

U.S. Environmental Protection Agency

August 2008

Version 1.3

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Climate Leaders *is an EPA industry-government partnership that works with companies to develop comprehensive climate change strategies. Partner companies commit to reducing their impact on the global environment by setting aggressive greenhouse gas reduction goals and annually reporting their progress to EPA.*

Introduction

An important objective of the Climate Leaders program is to focus corporate attention on achieving cost-effective greenhouse gas (GHG) reductions within the boundary of the organization (i.e., internal projects and reductions). Partners may also use reductions and/or removals which occur outside their organizational boundary (i.e., external reductions or "offsets") to help them achieve their goals. To ensure that the GHG emission reductions from offsets are credible, Partners must ensure that the reductions meet four key accounting principles:

- ***Real:*** The quantified GHG reductions must represent actual emission reductions that have already occurred.
- ***Additional:*** The GHG reductions must be surplus to regulation and beyond what would have happened in the absence of the project or in a business-as-usual scenario based on a performance standard methodology.
- ***Permanent:*** The GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.
- ***Verifiable:*** The GHG reductions must result from projects whose performance can be readily and accurately quantified, monitored and verified.

This paper provides a performance standard (accounting methodology) for greenhouse gas (GHG) offset projects that introduce more efficient (i.e., lower GHG emitting) boiler technology for space and hot water heating in commercial buildings. The accounting methodology presented in this paper addresses the eligibility of commercial boiler efficiency projects as greenhouse gas offset projects and provides measurement and monitoring guidance. Program design issues (e.g., project lifetime, project start date) are not within the scope of this guidance and are addressed in the Climate Leaders offset program overview document: Using Offsets to Help Climate Leaders Achieve Their GHG Reduction Goals.[1]

Description of Project Type

Commercial boiler systems are used for space and hot water heating throughout the United States. They provide heat to 15% of all commercial buildings and 29% of U.S. building floorspace area.[2] The major source of GHG emissions from a boiler system is

[1] Please visit http://www.epa.gov/climateleaders/resources/optional-module.html to download the overview document.
[2] U.S. Energy Information Administration, Commercial Buildings Energy Consumption Survey (CBECS) (Washington, DC, 2003).

carbon dioxide (CO_2) from the combustion of fossil fuels in the boiler. Other minor sources of GHGs can include methane (CH_4) from leaks in the natural gas distribution system and CH_4 and nitrous oxide (N_2O) as byproducts of combustion processes.

This section provides information on the general parameters that the proposed boiler project must match to use this performance standard.

Technology/Practice Introduced. This document addresses the improved efficiency of commercial boilers used for space and water heating. These efficiency improvements can be achieved by retrofitting; by replacing an existing boiler with new boiler technology; by purchasing a more efficient boiler to meet new demand; or, by switching from fuel oil or coal-based electricity to a lower GHG emitting fuel (such as natural gas).

GHG emission reductions also can be achieved through energy efficiency improvements in the steam/hot water distribution system, the boiler auxiliaries, or in building efficiency improvements. This performance standard, however, is not applicable for such projects, or for the decommissioning of boilers. This performance also is not applicable for projects introducing a new, or improving the efficiency of an existing, electricity-fired boiler.

Project Size/Output. This accounting methodology applies to all commercial boilers within the United States with an input capacity between 300,000 and 8 million Btu per hour.

Project Boundary. This section provides guidance on which physical components, and associated greenhouse gases, must be included in the project boundary for a commercial boiler efficiency project.

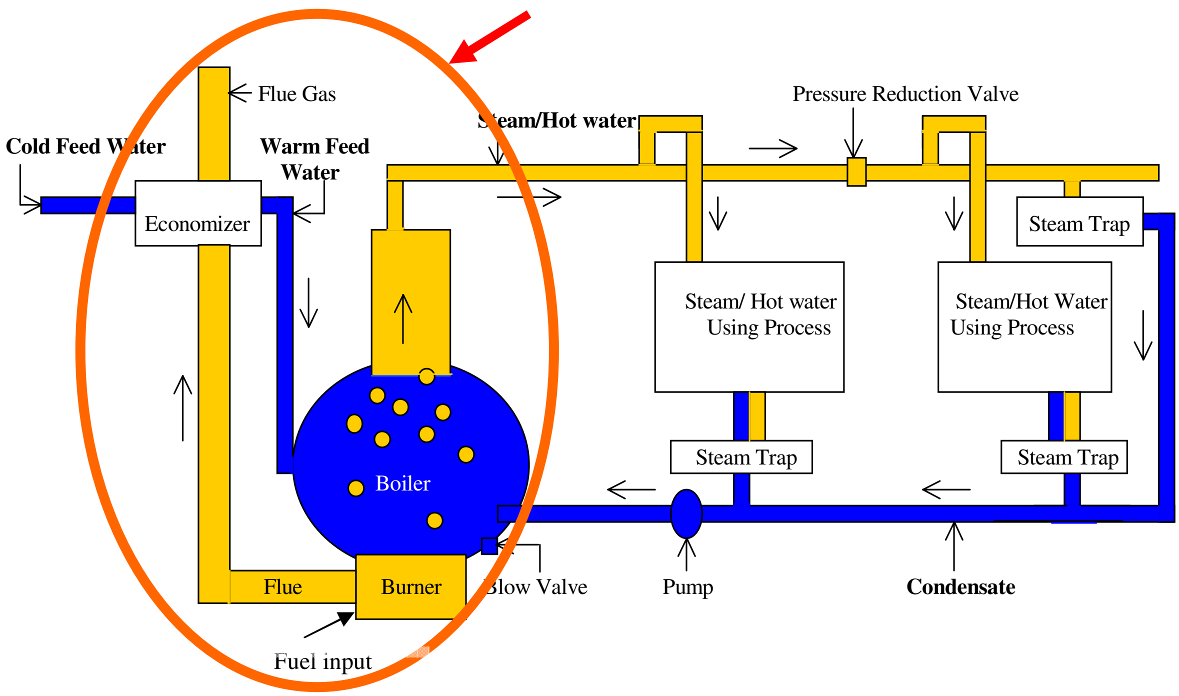
Physical Boundary: The physical boundary of the project includes any component of the commercial boiler that will change between the baseline conditions and implementation of the project. In most cases, the physical boundary should be limited to the boiler unit, which includes the boiler, burner, flue stack and economizer (see Figure 1). The rated annual fuel utilization efficiency or thermal efficiency of the boiler unit will depend on the interaction of these components.

Upstream or downstream adjustments to the physical boundary must be made, however, to incorporate emissions changes in the following special cases:

- projects where the new boiler results in emissions changes in the steam distribution system; and,

- projects where the electricity use associated with the boiler auxiliaries (e.g., fans, pumps, conveyors) changes as a result of the new boiler. In this case, the equipment causing the changes in emissions from electricity should be included in the physical boundary, either as direct emissions or indirect emissions (if generated off-site).

Figure 1. Physical Boundary for Commercial Boiler Projects



Greenhouse Gas Accounting Boundary. The GHG accounting boundary for a commercial boiler efficiency project includes primarily the CO_2 emissions from the combustion of fossil fuels. Other minor sources of GHGs may be CH_4 from leaks in the natural gas distribution system (generally small), and CH_4 and N_2O as byproducts of combustion. The GHG accounting boundary for commercial boiler projects should, therefore, include all CO_2, CH_4 and N_2O emissions. Appendix II, Table IIb provides default emission factors for CH_4 and N_2O.

Temporal Boundary. An annual accounting boundary should be used for commercial boiler projects. Emissions from a commercial boiler can fluctuate during the course of a year due to changing activity schedules and seasonal climate patterns. An annual accounting boundary will account for these fluctuations.

Leakage. Leakage is an increase in greenhouse gas emissions or decrease in sequestration caused by the project but not accounted for within the project boundary. The underlying concept is that a particular project can produce offsetting effects outside of the physical boundary that fully or partially negate the benefits of the project. Although there are other forms of leakage, for this performance standard, leakage is limited to activity shifting – the displacement of activities and their associated GHG emissions outside of the project boundary.

Potential sources of leakage from a boiler project could result from an increase in GHG emissions at another site, if the existing higher emitting boiler is retired early before the end of its useful life and used elsewhere in the facility or resold for use in another application. If the old boiler is sold to replace another boiler at the end of its life instead of buying a more efficient boiler (defined as a boiler with a performance equal to, or better than, the performance threshold), the difference in CO_2 emissions between the replacement boiler and the performance threshold are considered leakage and must be quantified and subtracted from the emission reductions of the project.

If it is determined that significant emissions that are reasonably attributable to the project occur outside the project boundary, these emissions must be quantified and included in the calculation of reductions. No specific quantification methodology is required. All associated activities determined to contribute to leakage should be monitored.

Regulatory Eligibility

The performance standard subjects greenhouse gas offset projects to a regulatory "screen" to ensure that the emission reductions achieved would not have occurred in the absence of the project due to federal, state or local regulations. In order to be eligible as a GHG offset project, GHG emissions must be reduced below the level effectively required by any existing federal, state, or local policies, guidance, or regulations. This may also apply to consent decrees, other legal agreements, or federal and state programs that compensate voluntary action.

Federal Regulations. There are Federal standards in place for oil- and natural gas-fired boilers that must be met or exceeded by the GHG project in order to be eligible for offsets. These minimum combustion and thermal efficiency standards were first introduced as part of the Energy Policy Act (EPAct) of 1992 and were adopted from standards developed by the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE). The U.S. Department of Energy (DOE) makes a determination regarding adoption of any updated standards within a year of their release by ASHRAE. The most recent year for which DOE has made a determination is for the ASHRAE 1999 standard. The project developer should review updated standards.

State and Local Regulations. Some state and local governments may have additional efficiency standards that should be reviewed.

Determining Additionality - Applying the Performance Threshold

This section describes the performance threshold (additionality determination) which a commercial boiler project must meet or exceed in order to be considered as a GHG project offset.

Additionality Determination. The additionality determination represents a level of performance that, with respect to emission reductions or removals, or technologies or practices, is significantly better than average compared with recently undertaken practices or activities in a relevant geographic area. Any project that meets or exceeds the performance threshold is considered "additional" or beyond that which would be expected under a "business-as-usual" scenario.

The development and application of the performance threshold is dependent on whether the GHG offset project is a retrofit or new construction. This distinction is based on the assumption that fuel switching will likely not be a viable option for retrofit projects, but is viable for new construction.

The type of performance threshold used for a commercial boiler project is an emissions rate. The threshold represents a level of performance (emissions rate) that is beyond that expected compared to the efficiencies of recently installed boilers. For both retrofits and new construction, the performance thresholds are based on the energy efficiency and resulting CO_2 emissions of commercial boilers installed since 1990 and use the metric of $KgCO_2$/MMBtu.

For both retrofits and new construction, a performance threshold of approximately the top 20th percentile has been selected. Table 1 provides the threshold levels for retrofit and new construction projects. Background information describing the derivation of these thresholds can be found in Appendix I.

Table 1. Performance Thresholds for Boiler Projects

Commercial Boiler Project Type	Project Fuel Type	Thermal Efficiency	Performance Threshold, Emissions per Heat Output ($KgCO_2$/MMBtu)
Retrofit	Oil-fired	86%	85
	Natural Gas-fired	84%	63
New Construction	All fuels	84%	63

Quantifying Emissions Reductions

Quantifying emission reductions from a commercial boiler project encompasses four steps: two are pre-project implementation (selecting the emissions baseline and estimating project emission reductions) and two are post-project implementation (monitoring and calculating actual project reductions).

Selecting and Setting an Emission Baseline: The emissions baseline for a commercial boiler project depends on whether the project involves the retrofit of an existing boiler or new construction. The emission baselines are presented below:

1. **Retrofit**. For projects involving the retrofit or early replacement of a commercial boiler, the baseline should be equal to the average annual emissions of the *existing boiler* (i.e., the boiler prior to retrofit) in $KgCO_2$ equivalent.

2. **New Capacity.** For projects involving procurement of a new boiler, or the replacement of a boiler at the end of its lifetime, the emissions rate of the performance threshold in Table 1 is used in the baseline calculation. It is important to note that the performance threshold is only based on direct CO_2 emissions. When developing the baseline for new construction, indirect emissions from electricity, as well as emissions of CH_4 and N_2O must be added to the direct CO_2 emissions in order to estimate total CO_2 equivalent emissions.

In cases where special adjustments were made to the physical boundary to address fuel or electricity changes upstream or downstream from the boiler itself, these must also be included in the baseline.

Estimating Project Emission Reductions. To estimate the potential GHG emission reductions from the offset project, the project proponent must compare emissions from the baseline with emissions from the proposed project.

Estimating baseline emissions. Separate equations are presented for estimating baseline emissions from retrofit projects (Equations A,B,C) and new capacity (Equations D,E).

Retrofits

Equation A.

Baseline CO_2 emissions $_{retrofits}$ = $(F_i * EF_i) + (EL * EF_{el})$

Where:

i= fuel type

F_i= fuel consumption, MMBtu (use the average annual fuel consumption for the past three years)

EF_i= emission factor of fuel type i, kg CO_2/MMBtu

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

EF_{el} = emission factor for electricity, kg CO_2/MWh. If the emissions intensity of the electricity being purchased is known (for example, through contacting the local power supplier), the corresponding emission factor should be used. Where the specific emissions profile of the purchased electricity is not known, the project developer should use the relevant regional electric power generation emission factors for the electricity component of their emissions.

Equation B.

Baseline CH_4 and N_2O emissions $_{Retrofits}$= $(F_i * EF_{CH4}) + (F_i * EF_{N20}) + (EL * EF_{el, CH4}) + (EL * EF_{el, N2O})$

Where:

Baseline CH_4 and N_2O emissions = CH_4 and N_2O emissions from commercial boilers, $KgCO_2e$

i= fuel type

F= fuel consumption, MMBtu (use the average annual fuel consumption from the boiler during the past three years)

$EF_{CH4,}$ $EF_{N20,}$ = Fuel-related CH_4 and N_2O emission factors, respectively, $KgCO_2e/MMBtu$

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

$EF_{el,CH4,}$ $EF_{el, N20}$= Electricity-related CH_4 and N_2O emission factors, respectively, KgCO2e/MWh. If the emissions intensity of the electricity being purchased is known (for example, through contacting the local power supplier), the corresponding emission factor should be used. Where the specific emissions profile of the purchased electricity is not known, the applicant should use default values.

Equation C.

Total Baseline GHG Emissions $_{\text{Retrofits}}$ = Equation A + Equation B.

New Capacity

Total CO_2 equivalent emissions also must be calculated when estimating baseline emissions from new construction. Baseline CO_2 emissions for new construction are based on the performance threshold for the project fuel type (Equation D). Because the performance threshold reflects only CO_2 emissions, CH_4 and N_2O emissions must be added to the calculation of CO_2 emissions. The calculation for non-CO_2 emissions follows Equation B above, but uses estimates for project-level fuel and electricity consumption.

Equation D.

Baseline CO_2 Emissions $_{\text{New Construction}}$ = PT * F_i

Where:

PT = performance threshold for the project fuel type, $KgCO_2/MMBtu$ (Table 1)

F_i = estimated fuel consumption for project, MMBtu

Equation E.

Total Baseline GHG Emissions $_{\textbf{New Construction}}$ = Equation B + Equation D

Estimating project emissions. Project-related emissions are estimated using the same equations above. Similar to the baseline calculations outlined above, the estimated annual fuel consumption of the project boilers is multiplied by the applicable CO_2 emission factors and the emission factors for CH_4 and N_2O. Emissions from purchased electricity also are included to estimate total project-related CO_2 equivalent emissions.

Estimating project-related emission reductions. Emission reductions are estimated using Equation F.

Equation F.

Reductions $_{\textbf{project}}$ = Emissions $_{\textbf{baseline}}$ – Emissions $_{\textbf{project}}$

Monitoring

Four monitoring options are available for monitoring of emissions from commercial boilers: (1) direct fuel volume measurement; (2) steam flow measurement; (3) direct stack CO_2 measurement; and (4) dealer certified fuel volume measurement.

All commercial boiler greenhouse gas offset projects must also monitor any regulatory requirements (or changes in regulatory requirements) or substantive changes in the project that might affect the continued eligibility of the project as a greenhouse gas offset project.

The following methods are used for calculating CO_2 emissions. Data on the heating value of the fuel inputs should also be collected in order to estimate CH_4 and N_20 emissions using the default values in Appendix II, Table IIb.

Direct Fuel Volume Measurement Approach. This method uses a volume meter positioned in the fuel line leading directly to the boiler to measure the volume of fuel burned in the boiler. At the end of each year, or some other designated period, the total volume of fuel burned is read from the meter and used in *Equation G* to estimate the emissions of CO_2 from the boiler during that period. For natural gas-fired boilers, the method also requires that temperature and pressure gauges be inserted in the fuel line to measure the temperature and pressure of the fuel gas. The average gas pressure and temperature during the measurement period is used in the equation to compensate for changes in gas density due to these two factors. Fuel oil is relatively incompressible and its density does not change appreciably during the year due to temperature and pressure fluctuations.

Equation G.

$E = V \times CF \times (44/12) \times 520/T \times P/14.7$

Where:
- E = CO_2 emissions (tons/year)
- V = volume of fuel combusted (mscf/yr or mgal/yr)
- CF = carbon factor (ton/mscf or ton/mgal)
- $44/12$ = ratio of the weight of CO_2 to carbon
- $520/T$ = ratio of standard temperature to temperature of fuel (°R)
- $P/14.7$ = ratio of fuel pressure to standard pressure (psia)

Steam Flow Measurement Approach. The steam flow measurement method uses the quantity of steam produced by the boiler and engineering data to calculate the CO_2 emissions from the boiler. This method is applicable to boilers fired with natural gas and fuel oil. In this method, the steam produced by the boiler is measured in the steam line just after it exits the boiler. Annually, or some other designated period, the quantity of steam produced by the boiler is used to calculate the CO_2 emissions for the period using *Equation H*. In addition to the annual steam production, *Equation H* also requires the boiler owner to obtain the heat rate of the boiler, which is usually expressed in terms of million Btu of fuel required to produce a million Btu of steam. The heat rate is also called the overall thermal efficiency of the boiler.

Equation H.

$E = Q \times HR \times 1/HV \times CF \times (44/12)$

Where:
- E = CO_2 emissions (tons/year)
- Q = quantity of steam produced (MMBtu/yr)
- HR = heat rate of the boiler (MMBtu of fuel/MMBtu of steam)
- HV = heating value of the fuel (MMBtu/mgal or MMBtu/mscf)
- CF = carbon factor (ton/mscf or ton/mgal)
- $44/12$ = ratio of the weight of CO_2 to carbon

An orifice meter and an associated digital flow totalizer are used to provide a continuous digital display of the current steam flow rate and accumulated steam flow. These totalizers can be programmed to output values in any desired unit, which for this method should be million Btu of steam flow. The orifice meter is placed in the steam line as it exits the boiler. The orifice meter is factory calibrated, but should be re-calibrated annually. Temperature and pressure sensors are used by the totalizer to determine the quantity of heat conveyed by a unit of steam. These sensors are located in the steam line, adjacent to the orifice meter. The sensors are factory calibrated and do not require further calibration.

Direct Stack CO_2 Measurement Approach. The direct stack CO_2 measurement methodology uses a set of three instruments to directly measure the CO_2 emissions from the boiler stack. A gas analyzer is used to measure the concentration of CO_2 and a flow rate meter is used to measure the flow rate of the flue gases in the boiler stack. A data integrator is used to integrate the CO_2 concentration and the flue gas flow rate over a given time period, such as a year, to calculate an annual CO_2 emission rate from the natural gas boiler.

Dealer Certified Fuel Volume Measurement Approach. An alternative to the direct fuel volume measurement method is the use of dealer certified fuel volume measurements that are provided by the fuel dealer as part of their billing records. Although there is no national standard for the accuracy of retail fuel deliveries, all but one state (North Dakota) has adopted the guidelines set by the *National Conference on Weights and Measures (NCWM)*, known as *Handbook 44*.[3] Under this method, the boiler owner is not required to install and maintain any fuel metering instrumentation. However, the project developers are required to maintain fuel delivery meters that meet the accuracy requirements of *Handbook 44,* and documentation that reported sales volumes comply with these requirements. If there are multiple boilers, separate fuel use records for must be provided for each boiler.

To estimate CO_2 emissions, the boiler owner must obtain a certified record of annual fuel use from the fuel retailer and use this fuel volume in *Equation G* to calculate the tons per year of CO_2 emissions. *Equation G* also requires the temperature and pressure for which the certified fuel volume has been adjusted.

Calculating Actual Project Reductions. Quantifying project GHG emissions reductions occurs after the project has been implemented and monitored. To quantify project reductions, apply the equations presented in the section on estimating project emission reductions, using actual monitored project data rather than estimates, and adjust for any leakage (Equation I).

Equation I.

$$\textbf{Reductions}_{\textbf{project}} = \textbf{Emissions}_{\textbf{baseline}} - \textbf{Emissions}_{\textbf{project}} \ \textbf{(+/- leakage adjustments)}$$

[3] The National Conference on Weights and Measures (NCWM) developed the "Specifications, Tolerances, and Other Technical Requirements for Weighting and Measuring Devices" in partnership with the Office of Weights and Measures of the National Institute of Standards and Technology (NIST). This set of guidelines is also known as Handbook 44. http://ts.nist.gov/ts/htdocs/230/235/h130 04/PDF/h130 04all.pdf

Appendix I. Development of the Performance Threshold – Data Set

The two datasets referenced in developing the performance thresholds in Table 1 are the New Jersey Electric & Gas Utilities: Commercial Energy Efficient Construction Baseline Study and the U.S. Energy Information Administration's Commercial Buildings Energy Consumption Survey (CBECS). In addition, background information derived from two state energy efficiency programs contributed to the analysis.

The New Jersey study involved on-site audits of 96 new commercial buildings in 1999. It did look at boiler fuel types, but not efficiencies. A notable finding was that fuel oil boilers were used in only 3% of new construction and renovation. The remainder was gas and electric. Table Ia summarizes the relevant results of that study.

Table Ia. Recently installed commercial boilers in New Jersey (1999)

Project Type	Electric	Natural Gas	Oil
New Construction	0%	95%	5%
Renovation	34%	66%	0%
Grand Total	14%	83%	3%

EIA's CBECS provided detailed disaggregated information on fuel consumption by fuel type and region for over the past 70 years (Table Ib). The most important trend of note here is the decreased fraction of fuel oil used in boilers in modern buildings in the various regions.

The analysis presented assumes that the overall penetration of renewable energy in the commercial sector is low. According to EIA, in 2003 only a small fraction (0.7%) of buildings used municipal solid waste or landfill gas to fire their boilers. There is growing interest in biodiesel, however there are no available data to include this fuel in the analysis at this point in time.

Table Ib. Commercial boiler fuel consumption by building construction year

	Total Fuel Consumption (Trillion Btu)										
	Before 1920	1920 - 1945	1946 - 1959	1960 - 1969	1970-1979	1980-1989	1990-1999	2000-2003	% of Regional Fuel Use - 1990-1999	% of Regional Fuel Use - 2000-2003	% of Regional Fuel Use - 1990-2003
Fuel Oil											
Northeast	17.58	46.61	33.43	15.96	11.59	2.48	4.90	3.51	8.5%	7.2%	7.9%
Mid-west	9.16	0.67	5.19	1.78	1.05	0.26	0.71	1.16	1.0%	3.1%	1.7%
South	2.42	0.85	0.80	2.54	1.96	0.90	0.80	0.06	0.8%	0.2%	0.6%
West	0.00	0.01	0.58	3.30	0.06	0.46	0.29	0.33	1.0%	1.6%	1.2%
Natural Gas											
Northeast	26.15	69.52	41.81	35.68	34.19	24.84	21.62	23.98	37.6%	49.3%	43.0%
Mid-west	48.49	51.25	56.03	64.96	74.34	31.96	36.85	12.89	52.5%	34.1%	46.1%
South	9.94	11.53	32.89	30.85	33.07	45.10	36.12	13.69	36.0%	34.7%	35.6%
West	11.72	11.06	15.61	24.91	35.63	51.21	12.46	9.43	42.4%	46.2%	43.9%
Electricity											
Northeast	25.83	35.51	24.16	32.69	40.76	30.80	30.91	21.17	53.8%	43.5%	49.1%
Mid-west	15.02	18.98	24.77	34.35	66.73	37.29	32.63	23.72	46.5%	62.8%	52.2%
South	9.55	12.73	32.01	35.50	76.45	66.75	63.50	25.74	63.2%	65.2%	63.8%
West	3.68	9.78	11.06	23.25	45.38	70.48	16.65	10.67	56.6%	52.2%	54.8%

Source: U.S. Energy Information Administration, Commercial Building Energy Consumption Survey, 2003.

Spatial Area – A national spatial area was used to develop the performance threshold for commercial boiler retrofit projects. Across the United States, there are two fuel-specific thresholds for retrofits; one for gas-fired and one for oil-fired boilers based on the thermal efficiency and subsequent emissions rate. For new construction, one threshold was initially developed for each of the regions in the United States- Northeast, Midwest, South and West in the belief that regional fuel availability might impact the regional emissions rates of boilers. The results of this analysis, however, show that three out of the four regions had the same emissions rate, the South being the exception with a higher emissions rate. Therefore, a national spatial range was selected for all commercial boiler projects.

Temporal Range –The temporal range for the performance thresholds for retrofits and new construction is based on the performance of commercial boilers operating in the United States between 1990 and 2003 (the most recent years for which data are available). Although minimum efficiency standards on the Federal level for commercial boilers have remained unchanged since adoption of ASHRAE Standard 90.1-1999, data show that the overall fuel mix in boilers has changed slightly, with a decrease in the use of fuel oil partially being offset by an increased use of electricity (a portion of which is generated by coal).

Table Ic illustrates the regional breakdown of fuel use by boilers, with performance thresholds equal to the top 25th, top 20th and top 10th percentiles identified, while Table 1d provides background information on how boiler efficiency relates to emissions.

Table Ic. Commercial Boiler Performance Thresholds Based on Emissions-Intensity criteria (1990-2003 CBECS Data)

	Percentage of regional use in boilers - 1990-2003			
	North-east	**Mid-west**	**South**	**West**
Fuel Oil Boilers	7.9%	1.7%	0.6%	1.2%
Fuel Gas Boilers	43.0%	46.1%	35.6%	43.9%
Electric Boilers	49.1%	52.2%	63.8%	54.8%
Estimated boiler efficiency at 25th percentile	82%	82%	81%	82%
Estimated boiler efficiency at 20th percentile	83%	83%	82%	83%
Estimated boiler efficiency at 10th percentile	85%	85%	84%	85%
Performance threshold at 25th percentile (KgCO_2/MMBtu)	**64.7**	**64.7**	**65.5**	**64.7**
Performance threshold at 20th percentile (KgCO_2/MMBtu)	**63.9**	**63.9**	**64.7**	**63.9**
Performance threshold at 10th percentile (KgCO_2/MMBtu)	**62.4**	**62.4**	**63.2**	**62.4**

Source: Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey.

Table Id. Relationship between Boiler Thermal Efficiency and Emissions

Boiler Thermal Efficiency	Emissions per Heat Output ($KgCO_2$/MMBtu)
80%	66.3
81%	65.5
82%	64.7
83%	63.9
84%	63.2
85%	62.4
86%	61.7
87%	61.0
88%	60.3
89%	59.6
90%	59.0
91%	58.3
92%	57.7
93%	57.1
94%	56.4

Appendix II. Tables for Estimating and Calculating Emissions

Table IIa. CO_2 Emission Factors for Various Fuels

Fuel Type	kg CO_2/MMBtu
Natural Gas	53.06
Distillate Fuel Oil	73.15
Residual Fuel Oil	78.80
Coal	93.98

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006, April 2008. U.S. Environmental Protection Agency. Note: Industrial coal value based on Year 2006 "Industrial Other Coal" value.

Table IIb. Default CH_4 and N_2O Emission Factors for Natural Gas, and Fuel Oil, Coal

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMBtu)
Natural Gas	CH_4	0.105
	N_2O	0.031
Petroleum (Commercial sector)	CH_4	0.231
	N_2O	0.186
Petroleum (Industrial sector)	CH_4	0.063
	N_2O	0.186
Coal	CH_4	0.231
	N_2O	0.496

Sources: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IIc. Default CH_4 and N_2O Emission Factors for Electricity

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMbtu)
Natural Gas	CH_4	0.021
	N_2O	0.031
Petroleum	CH_4	0.063
	N_2O	0.031
Coal	CH_4	0.021
	N_2O	0.496

Note: Electricity emissions of CH_4 and N_2O relate to the fuel used to produce the electricity. Information on fuel type will be needed to estimate CH_4 and N_2O.
Sources: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IId. Emission Factors for Electricity Use by Project Equipment by eGRID Subregion (2004)

eGRID Subregion	States included in eGRID Subregion	NERC Region	Emission factor for electricity used by project equipment (kg CO2/kWh)
AKGD* (Alaska Grid)	AK	ASCC	0.604
AKMS (Alaska Miscellaneous)	AK	ASCC	0.630
AZNM (WECC- Southwest)	AZ, CA, NM, NV, TX	WECC	0.634
CAMX (WECC- California)	CA, NV, UT	WECC	0.572
ERCT (Texas)	TX	ERCOT	0.600
FRCC (Florida)	FL	FRCC	0.612
HIMS (Hawaii- Miscellaneous)	HI	HICC	0.738
HIOA* (Hawaii- Oahu)	HI	HICC	0.783
MORE (Midwest- East)	MI, WI	MRO	1.005
MROW (Midwest- West)	IA, IL, MI, MN, MT, ND, NE, SD, WI, WY	MRO	1.050
NEWE (New England)	CT, MA, ME, NH, NY, RI, VT	NPCC	0.641
NWPP (WECC- Northwest)	CA, CO, ID, MT, NV, OR, UT, WA, WY	WECC	0.770
NYCW (New York- NYC, Westchester)	NY	NPCC	0.788
NYLI (New York- Long Island)	NY	NPCC	0.686
NYUP (New York- Upstate)	NJ, NY, PA	NPCC	0.821
RFCE (RFC- East)	DC, DE, MD, NJ, PA, VA	RFC	0.800
RFCM (RFC- Michigan)	MI	RFC	0.880
RFCW (RFC- West)	IL, IN, KY, MD, MI, OH, PA, TN, VA, WI, WV	RFC	0.951
RMPA (WECC- Rocky Mountains)	AZ, CO, NE, NM, SD, UT, WY	WECC	0.778
SPNO (SPP- North)	KS, MO	SPP	1.007
SPSO (SPP- South)	AR, KS, LA, MO, NM, OK, TX	SPP	0.699
SRMV (SERC- Mississippi Valley)	AR, LA, MO, MS, TX	SERC	0.634
SRMW (SERC- Midwest)	IA, IL, MO, OK	SERC	0.979
SRSO (SERC- South)	AL, FL, GA, MS	SERC	0.847
SRTV (SERC- Tennessee Valley)	AL, GA, KY, MS, NC, TN	SERC	0.941
SRVC (SERC- Virginia/Carolina)	GA, NC, SC, VA, WV	SERC	0.890

Note: The emission factors in Table II.d reflect variations in electricity use by project equipment across regions and load type (i.e., base versus non-baseload). Coincident peak demand factors from a 2007 ACEEE study were combined with EPA's eGRID emission factors for baseload and non-baseload power to derive the emission factors presented in this table.[4,5]

[4] York, D. Kushler, M. Witte, P. "Examining the Peak Demand Impacts of Energy Efficiency: A Review of Program Experience and Industry Practice." American Council for and Energy-Efficient Economy (ACEEE). February 2007. http://www.aceee.org/pubs/u071.htm.

[5] The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes of electric power systems, available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

United States Environmental Protection Agency

Office of Air and Radiation (6202J)

EPA400-S-08-003

August 2008

www.epa.gov/climateleaders