Boiler Efficiency Projects

Development of Issues Papers for GHG Reduction Project Types:
Boiler Efficiency Projects

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From Science to Solutions

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CCAR Boiler Efficiency Projects

Topic: Increasing the efficiency of and reducing GHG emissions associated with new installations and the installed base of boilers.

1 Background – Boilers

This paper investigates the options for greenhouse gas emission reductions from the installation of new and retrofit high efficiency boilers. The types of boilers addressed are industrial boilers, commercial boilers, biomass boilers, cogeneration boilers and residential boilers. Each of these boiler types have unique technological characteristics and regulatory requirements that need to be addressed to determine if an appropriate performance standard can be developed. Some boiler types have additional issues associated with leakage – primarily biomass boilers. Residential boilers have similar regulatory and technology issues as the commercial boilers, but are widely distributed in the general population and GHG emission reduction ownership "rights" are an issue that must also be considered. This paper explores these issues and makes recommendations on if and how to proceed with GHG offset methodologies.

Industrial boilers

Industrial boilers, which are often classified as water-tube and fire-tube boilers typically have a capacity greater than 10 million Btu per hour (MMBtu/Hour)[1] and are regulated by the Federal Clean Air Act (CAA) for criteria pollutant emissions. An industrial boiler is defined by its common function – a boiler that provides heat in the form of hot water or steam for co-located industrial process applications.

There are approximately 43,000 industrial boilers in the United States.[2] The majority of industrial boilers (71%) are located at facilities in the food, paper, chemicals, refining and primary metals industries. Almost 78 percent of all boiler units use natural gas as a fuel. 56 percent of industrial boiler capacity is natural gas-fired, although certain industries (refining, paper, primary metals) have large shares of boiler capacity that are fired with by-product fuels. Industrial boilers are found in every census region but are more concentrated in the East North Central (ENC), South Atlantic (SA) and West South Central (WSC) regions, which contain more than 60 percent of the capacity.

Commercial Boilers

Commercial boilers are typically in the size range of 300,000 BTU/hr to 10 million BTU/hr. Commercial boiler systems are used for space and hot water heating throughout the United States. . The reason for this difference is those boilers are more common in larger floor space commercial applications. Table C31 from CBECS shows this trend well – only 11% of building gas heating requirements come from boiler systems in buildings under 10,000 square feet. In commercial buildings between 10,000 and 100,000 square feet, this percentage triples to 31%. In

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[1] *Characterization of the U.S. Industrial Commercial Boiler Population*, Oak Ridge National Laboratory, May 2005
[2] *Characterization of the U.S. Industrial Commercial Boiler Population*, Oak Ridge National Laboratory, May 2005

large commercial buildings above 100,000 square feet, 41% of gas heating requirements come from boiler systems. The reason for this trend is discussed further in this paper, but stems from the fact that boiler systems heating water are inherently more efficient than other heating systems heating air, however they are also more expensive. Thus, the larger building applications can typically justify the additional installed costs resulting form the energy savings.

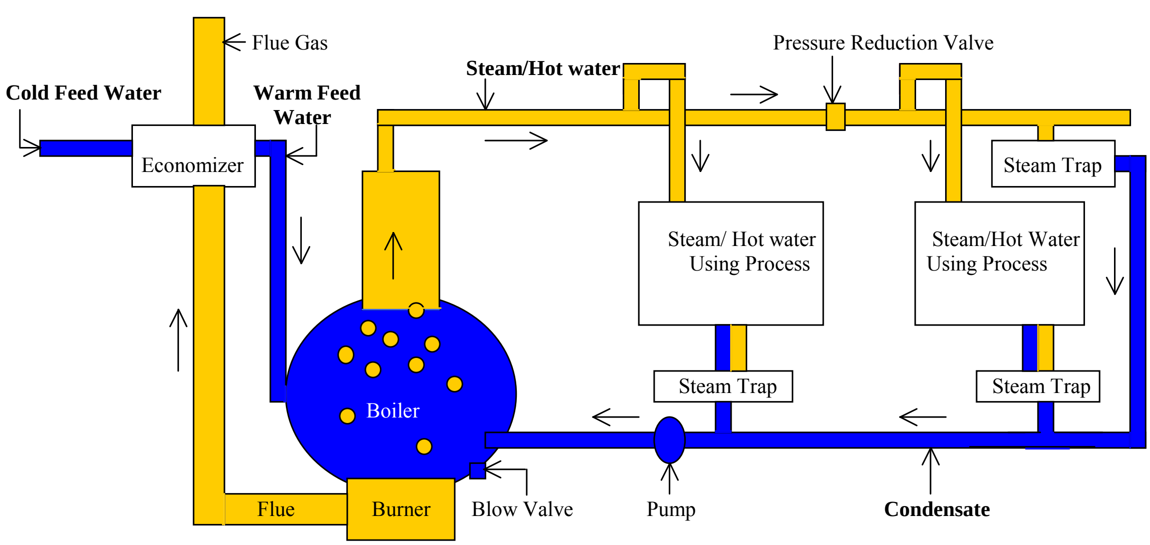
Commercial boilers are typically installed in a central heating plant within a campus or facility where steam or hot water is generated and then distributed throughout the building(s). The following table presents the installed base of commercial boilers in the US[3].

Table 1 Commercial Boilers Installed in the US

Building Type	Number of Boilers	Aggregate Boiler Capacity (MMBtu/Hr)	Average Capacity per Facility (MMBtu/hr)
Education	35,895	128,790	3.6
Office	28,030	297,090	10.6
Health	15,190	317,110	20.9
Other	11,900	88,970	7.5
Lodging	10,545	140,830	13.4
Public Assembly	7,280	55,205	7.6
Retail	5,585	47,230	8.5
Warehouse	5,365	72,385	13.5
Total	**119,790**	**1,147,610**	**9.6**

An illustration of a commercial heating system that employs a boiler is presented in the following figure.

Figure 1 Commercial Boiler System



[3] Consortium for Energy Efficiency Presentation

Biomass Boilers

Biomass boilers are solid fuel boilers that use carbon-based organic matter as the fuel source. Typical fuel sources include:

- Forrest and Mill Residue
- Agricultural Crops and Waste
- Wood and Wood Waste
- Fast-growing trees and plants
- Industrial waste

Biomass boilers are available in a range of sizes from residential to industrial classes. Biomass was the original residential heating source in the form of fireplaces and wood stoves. These early forms of the technology resulted in significant heat loss through the exhaust resulting in low efficiencies (less than 50%) and also had a high level of particulate emissions. The new technologies have achieved high efficiency levels (more than 80%) and have controls to regulate particulate emissions. Currently, the New York State Energy Research and Development Authority NYSERDA is funding a demonstration of this technology that addresses energy savings as well as improved particulate and CO emissions performance related to residential and commercial wood boilers, pellet stoves, and wood stoves.[4]

Cogeneration Boilers

Cogeneration boilers are a component of a power plant where they are used to create steam that drives a steam turbine to generate electricity. An example of this application is a coal-fired power plant. To increase the process efficiency, the heat from the steam that passes through the turbine can be recovered and used to provide heating in a large facility or through a district heating system. Typically, the main driver in these applications is the production of electricity. The boilers in these applications are typically larger than industrial boilers. The application of these boilers is normally in power plants with a capacity greater than 20 MW (utility scale power generation). Conventional cogeneration for commercial buildings typically is less than 5 MW and utilizes technologies that do not incorporate a boiler to drive the system such as reciprocating engines, micro turbines and combustion turbines.

Residential Boilers

Residential boilers are similar in form and function to commercial boilers. Residential boilers are less expensive and more easily available than commercial boilers as they are smaller than commercial boilers and can be more efficient. Residential boilers typically have an energy input of less than 300,000 BTU/hr and use a single-phase electrical supply. Residential boilers run on natural gas or fuel oil and compete with furnaces for space heating. Residences are typically heated with furnaces or boilers. Furnaces distribute the heat as hot air blown through a ducted system. Boilers develop either steam or hot water that is distributed through piping to radiators or heating coils. Boilers are predominately found in the northeast where there are lower outdoor

[4] http://www.nyserda.org/Press_Releases/2008/PressRelease20083009.asp

temperatures for long periods of time. In these areas, continuous heating through the radiators located throughout the residence provides a higher level of consistent comfort for the occupants. Oil-fired boilers are typically found in more rural areas where there may not be existing natural gas infrastructure near the residence. A summary of the residential heating systems shipped in for the years of 2003 through 2007 are presented below[5].

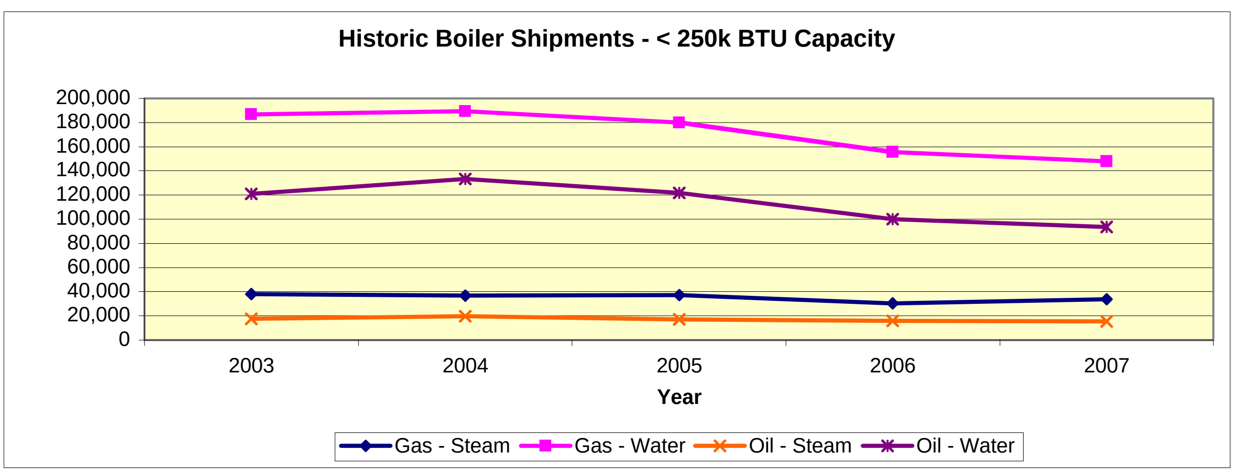
Table 2 Residential Heating System Sold in the U.S. (Quantity: 2003 -2007)

Year	2003	2004	2005	2006	2007
Boilers < 250,000 BTU					
Gas-Fired Boilers					
Steam	38,105	36,846	37,127	30,243	33,932
Water	186,627	189,417	179,717	155,499	147,873
Oil-Fired Boilers					
Steam	17,706	19,460	17,256	16,016	15,494
Water	120,764	133,288	121,678	99,801	93,642
Gas Furnaces	3,265,550	3,519,024	3,512,464	3,096,715	2,782,006

Table 3 Residential Heating System Sold in the U.S. (Percentage: 2003 -2007)

Year	2003	2004	2005	2006	2007
Boilers < 250,000 BTU					
Gas-Fired Boilers					
Steam	1.0%	1.0%	1.0%	0.8%	0.9%
Water	5.1%	5.2%	4.9%	4.3%	4.1%
Oil-Fired Boilers					
Steam	0.5%	0.5%	0.5%	0.4%	0.4%
Water	3.3%	3.7%	3.3%	2.7%	2.6%
Gas Furnaces	89.5%	89.8%	90.5%	90.7%	90.2%

Figure 2 Trends in Residential Boiler Shipments (2003 – 2007)



5 www.gamanet.org/gama/stats.nsf/

As can be seen from the above, furnaces are used much more commonly in home heating applications. Boilers have an inherent efficiency advantage over furnaces, in that a boiler transfers its heat to water and provide radiant heat and the furnace transfers its heat to air, which is much less efficient.

1.1 Greenhouse Gas Emissions from Boilers

The major source of GHG emissions from a boiler system is 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.

1.2 Boiler Fuel Types

The most common fuel types used for boilers are electricity, natural gas and oil. Industrial boilers also use by-product fuels that include black liquor (pulping residue), bark and wood chips in the paper industry, refinery gas and residual oil in the refining industry, and coke oven or blast furnace gas in the primary metals industry. The following table presents a summary of commercial boiler energy sources by census region for the period of 1990 to 2003[6]. Other statistics from the Energy Information Administration (EIA) indicate a similar fuel mix for residential boilers.[7]

Table 4 Boiler Energy Sources by Census Region (1990 – 2003)

Boiler Type	Northeast	Midwest	South	West
Fuel Oil Boilers	7.8%	1.7%	0.6%	1.2%
Natural Gas Boilers	43.0%	46.1%	35.6%	43.9%
Electric Boilers	49.1%	52.2%	63.8%	54.8%

This table evokes a natural question – should electric boilers be considered as another potential offset type? There has been no development of electric boiler offset protocols to date, primarily due to the fact that the power electricity supplied to the boiler application is inherently much less efficient (50% for modern natural gas power generators) than on-site combustion (over 80%), thus resulting in much higher effective emissions from electric boilers. If the electric grid gets to the point in the future where it is dominated by renewable energy, CCS, and nuclear, this situation would change, however that isn't expected for many years.

1.3 Energy Use and Efficiency of Boilers

Boilers typically operate to meet a desired heating load, which is to say that the output of the boiler can be easily adjusted to meet a load that is not constant. Industrial boilers operate to meet a process load that is driven by the production output for a product. Thus the level of production

[6] EIA, Commercial Buildings Energy Consumption Survey, Tables C-15, C-25, C-35 – Electricity, Natural Gas, Fuel Consumption by Region, 2003
[7] EIA, Residential Energy Consumption Survey, Table HC10.4 Space Heating Characteristics by U.S. Census Region, 2005

affects the annual output required from the boiler. Industrial boiler applications are usually a multiple boiler configuration that include a lead boiler that meets the base load requirements supported by a lag boiler that that supports the load that is in excess of the lead boiler capacity. In some case there is also a standby boiler that is ready for operation in the case of a failure of the lead or lag boiler or to support the process when one of the other boilers is out of service for scheduled routine maintenance. Note that during the course of the year, the designation of lead, lag and standby rotates through the boilers so that they have similar hours of operation over the course of year. While industrial boilers can load follow, they cannot be frequently cycled on and off as thermal cycling can damage the units. To accommodate this requirement, the lag and standby boilers are typically in a warm standby mode where the boiler is maintained at a temperature that will allow it to be placed into service in a short period of time. Note that in a warm standby mode of operation, fuel is consumed and no usable output is produced.

Commercial and residential boilers operate to meet a space heating and/or domestic hot water load. The space-heating load is driven significantly by the outdoor air temperature and therefore varies on a regional basis across the United States. A method to estimate the monthly and annual heating load of boiler used for space heating is by using a metric called the heating degree days (HDD). HDD values are published for all major weather stations across the United States. The HDD is developed for a specific base temperature (usually 65°F) and is calculated as the base temperature minus the daily average temperature divided by the base temperature. Climates and locations with higher HDDs have higher annual space heating loads. The following table presents the annual HDDs for a sample of climates in the US.

Table 5 Yearly Average Heating Degree Days

City	HDD
Barrow, Alaska	20,370
Bismarck, N.D.	8,932
Hilo, Hawaii	0
Kansas City, Mo.	5,326
Key West, Fl.	68
Yuma, Arizona	983

Source: The USA TODAY Weather Almanac

Commercial and residential domestic hot water loads are driven by the number and type of hot water fixtures in the facility and the type of facility. Typical hot water fixtures are sinks, showers, clothes washers, dishwashers, and utility sinks. The American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) provides estimates of the daily load for each type of fixture based on the type of facility and the average number of people in the facility[8]. These values can be used to estimate domestic hot water requirements for a facility. In most fuel based domestic hot water systems there is a hot water storage tank that is between the boiler and the load. The tank buffers the boiler from large instantaneous loads and boiler operates to maintain a storage temperature set point.

[8] ASHRAE Handbook – HVAC Applications, Service Water Heating

The efficiency of boilers is the ratio of heat output to the fuel input. The heat output is in the form of steam or hot water. Both forms of these output streams can be measured to calculate the quantity of energy produced by the boiler. The input fuel in the form of oil or natural gas can also be accurately measured to calculate the quantity of energy input into the boiler. When calculating the input energy value for the fuel, one must note the assumption for the value of the heat of combustion of the fuel as it typically expressed in the form of higher heating value and lower heating value. Higher Heating Values for a fuel include the full energy content as defined by bringing all products of combustion to 77°F (25° C). Natural gas typically is delivered by the local gas company with values of 1,000 - 1,050 Btu per cubic foot on this HHV basis. Since the actual value may vary from month to month some gas companies convert to Therms. A Therm is precisely 100,000 BTU. These measures all represent higher heating values. Lower heating values neglect the energy in the water vapor formed by the combustion of hydrogen in the fuel. This water vapor typically represents about 10% of the energy content. Therefore the lower heating values for natural gas are typically 900 - 950 Btu per cubic foot.

Losses in boilers that affect the efficiency include heat loss through the walls of the boiler, heat loss through the exhaust and not combusting 100% of the fuel provided to the system. Steam boilers also have a blow-down requirement. Boiler feed water often contains some degree of impurities, such as suspended and dissolved solids that accumulate inside the boiler during normal operation. The increasing concentration of dissolved solids can lead to carryover of boiler water into the steam, causing damage to piping, steam traps and even process equipment. The increasing concentration of suspended solids can form sludge, which impairs boiler efficiency and heat transfer capability. To avoid boiler problems, water must be periodically discharged or "blown down" from the boiler to control the concentrations of suspended and total dissolved solids in the boiler. Surface water blowdown is often done continuously to reduce the level of dissolved solids, and bottom blowdown is performed periodically to remove sludge from the bottom of the boiler. The blowdown water has been heated inside the boiler and therefore uses some of the fuel but does not result in useful heat output. Note, there are devices that can be incorporated into a boiler to recover some of the blowndown energy but these are not standard equipment at this time.

Commercial and residential boiler efficiencies are sometimes presented as AFUE (Annualized Fuel Utilization Efficiency) which is the ratio of the total useful heat the boiler delivers to the heat value of the fuel it consumes over the course of the year. This efficiency metric takes into account seasonal variability of the boiler operation.

2 Existing Quantification Methodologies, Remaining Uncertainties and Other Available Information

Standardized GHG project protocols have considerable administrative advantages over project specific protocols, which have to be developed, reviewed, and justified on a case-by-case basis. A key thrust if this section is that a standard GHG accounting protocol can be developed for the industrial, commercial and residential boiler applications. A standardized protocol has already been developed by EPA Climate Leaders for two of these categories – industrial and commercial boilers. Conversely, cogeneration and biomass boilers are not likely to be candidates for a standardized protocol in the near term. As presented above, cogeneration boilers are applicable to large power plant projects that are utility scale and have different regulations, operating requirements, and service provided (i.e. provision of electricity). Typical cogeneration technologies for commercial (non utility) applications are based on non-boiler technologies (i.e. reciprocating engines, micro turbines, fuel cells and combustion turbines).

Biomass boilers will have a high level of variability in input fuel. The variability will be represented in the annual changes in fuel characteristics for fuel from the same source as well as variable fuel characteristics for sources from region to region. This poses quantification challenges for both determining baseline emissions as well as project emissions. In the case of baseline emissions, older biomass boilers can have highly variable efficiencies and the accuracy of the emissions estimate will be questionable and will be inherently much more uncertain than fuel oil or fuel gas measurements. Some of this accuracy concern is mitigated by the fact that, for GHG inventory purposes, biomass CO_2 emissions are typically assumed to be zero, as the carbon content of the biomass combusted is assumed to balance out with the carbon sequestered in the biomass. In addition, accuracy concerns can be addressed with CEM measurements in the stack – this is discussed further in the monitoring section. The bigger issue is with quantification of project related emissions. Changes in land use patterns to develop biofuels can have very large GHG impacts. The US EPA Climate Leaders GHG Inventory Protocol Core Module Guidance document notes this concern by stating that zero CO_2 biomass emissions assume" that there is no net loss of biomass-based carbon associated with the land use practices used to produce these fuels," This is often not the case, however. Recent studies conducted by the State of California on biofuels[9] indicate that the life cycle GHG emissions from land use conversions to grow certain energy crops can be almost as high as fossil fuels. This is discussed further in the leakage section. The overall implication is that the current potential for standardization of biomass project baselines will be very problematic until a consensus is established on how to treat these leakage issues. Currently, the State of California is revising its GREET model used to develop the initial estimates on land use and biomass. The federal government is also researching this issue now. Until a consensus is established, biomass boiler projects may have to provide project specific baseline emissions and performance threshold data.

Industrial boilers are unique from commercial and residential boilers in that industrial boilers are not generally purchased as an "off-the-shelf" item that one simply selects based on the manufacturer's performance label. Manufacturers have models that they will construct given the specification provided by an engineer. From a performance perspective, the engineer will specify the desired design output capacity, steam pressure and temperature requirements, and emission thresholds that the boiler must meet. For example, the engineer may indicate that the required nitrogen oxides (NOx) emission threshold is at a level such that a low NOx version of the boiler is required, or that the new boiler must be guaranteed to meet carbon monoxide (CO) emission limits (as a surrogate for organic hazardous air pollutants) for compliance with the National Emission Standards for Hazardous Air Pollutants (NESHAP). The boiler manufacturer

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[9] *Full Fuel Cycle Assessment: Well to Wheels Energy Inputs, Emissions and Water Impacts: State Plan to Increase the Use of Non-Petroleum Transportation Fuels* - AB 1007 (Pavley) *Alternative Transportation Fuels Plan Proceeding*, REVISED Final Consultant Report #CEC-600-2007-004-REV. Original posted June 22, 2007; revised posted August 1, 2007.

will then apply the correctly sized boiler components to their boiler plan and engineered specifications before running a computer model to estimate the resulting operational characteristics, including thermal efficiency and emissions of the resulting boiler. For these reasons, the design efficiency of industrial boilers is relatively narrow and there are no "standard efficiency" and "high efficiency" versions of similar industrial boilers. In general, industrial natural gas-fired boilers producing steam have thermal efficiencies of 75% - 83%.[10]

However, in some cases, selecting higher performance burners and integrating more sophisticated controls can increase the efficiency of industrial boilers. Some of these technologies are standard practices while others are not commonly used. A technology-based performance standard can then be developed to evaluate GHG offset potential from industrial boilers. This was the approach used by EPA Climate Leaders.

The efficiency of boilers is defined either in terms of combustion efficiency or overall efficiency. Combustion efficiency is based on the fuel input energy less the exhaust energy loss divided by the fuel input energy. The overall efficiency is the gross output energy divided by the gross input energy. Overall efficiency is less than combustion efficiency due to the energy loss through the surface of the boiler (radiant heat loss). Commercial and residential boilers have efficiencies that are based on standardized testing protocols. Overall efficiency can only be determined through laboratory testing under specific operational parameters. Agencies that define these testing procedures are as follows[11]:

- The Hydronics Institute[12]: Cast Iron and Steel Heating Boilers
- American Gas Association[13]: Gas Fired Low Pressure Steam and Hot Water Heating Boilers
- American Boiler Manufacturers Association[14]: Packaged Fire-Tube Boilers
- US Department of Energy: Gas and Oil-Filed Boilers < 300,000 BTU/Hr input to determine the Annual Fuel Utilization Efficiency (AFUE)

As such, each boiler has a specified efficiency and a consumer can easily identify and select a higher efficiency product over a standard efficiency product. Minimum efficiency requirements for these boilers are mandated to manufacturers by the federal government (US Department of Energy), some states have minimum requirements for new construction energy efficiency standards and Energy Star sets a target to qualify as a high efficiency boiler. This lends itself well to the development of an emissions-based standardized protocol since efficiency and fuel use information can be converted directly into GHG emissions. An emissions-based GHG protocol was developed for commercial boilers for EPA Climate Leaders.

RGGI used an efficiency-based approach for boilers when developing their offset project types. RGGI set efficiency levels for commercial and residential boilers above which GHG offset projects would be eligible. These levels are essentially technology-based standards. Commercial gas boiler efficiency standards in the RGGI protocol were set at 88% AFUE for boilers less than

[10] http://alliantenergy.com/docs/groups/public/documents/pub
[11] ASHRAE Systems and Equipment Handbook, Boilers
[12] Testing and Rating Standard for Heating Boilers
[13] American National Standard Z21.13
[14] ASME Performance Test Code, Steam Generating Equipment (PTC 4.1)

300,000 Btu/h and 90% for boilers greater than 300,000 Btu/h, which only condensing boilers can achieve. Residential boiler efficiency standards were set at 90% AFUE.

2.1 Standardized GHG Accounting Protocols

Regional Greenhouse Gas Initiative (RGGI)

RGGI is a regional regulatory cap-and-trade program for greenhouse gas emissions reduction within the U.S. The program covers CO_2 emissions from electricity generators within the region. Through this program, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) commit to cap their emissions using the year 2000 as a base and then decrease the emissions 10 percent by 2019. RGGI states have agreed to distribute allowances mainly through regional auctions, allowances can also be traded on a secondary market where power plants can sell them or buy them.

In order to monitor and report CO_2 emissions under the RGGI regime, the owners and operators of the CO_2 budget units[15] must install all the required monitoring systems, which include systems required to monitor CO_2 concentrations, O_2 concentrations, stack gas flow rate, heat input and fuel flow rate.

Equation 1 presents the method used to estimate CO_2 emissions from the combustion of fossil fuels

Equation 1 CO_2 Emissions Calculation[16]

$$W_{CO_2} = \frac{\left(MW_C + MW_{O_2}\right) \times W_C}{2,000\, MW_C}$$

Where:
W_{CO_2} = CO_2 emitted from combustion, tons/day.
MW_C = Molecular weight of carbon (12.0).
MW_{O_2} = Molecular weight of oxygen (32.0)
W_C = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

EPA Climate Leaders

Climate Leaders is an EPA voluntary program where the industry sector and the government can enter into partnerships with the goal to develop long-term climate change strategies to reduce greenhouse gas GHG emissions over a 5 to 10 years period. The program covers all sources of the six major greenhouse gases (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6). The Climate Leaders protocol is based on the existent corporate GHG inventory protocol developed by the World

[15] A unit that is subject to the CO_2 Budget Trading Program requirements
[16] http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr;sid=61a1d77eeeeb657ad36abd59bcf6b13a;rgn=div9;view=text;node=40%3A16.0.1.1.4.9.1.6.12;idno=40;cc=ecfr

Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) and it consists of three major parts: (1) The design principles section, which includes guidance on how to define inventory boundaries, identify GHG emission sources and define a baseline year; (2) The core modules guidance section, which deals with required GHG emissions reporting issues from direct (e.g. stationary and mobile sources, GHG process related emissions and refrigeration and air conditioning) and indirect sources (e.g. electricity and steam purchases); and (3) The optional modules guidance section, which offers a customized approach to mitigate GHG emissions and includes the use of optional activities such as renewable energy, employee commuting, offset investments, offsite waste disposal, product transport, etc.[17]

GHG emissions coming from the operation of boilers are considered stationary combustion sources and fall within the Climate Leaders' direct sources definition. The combustion of fossil fuels in stationary combustion sources generates CO_2, CH_4 and N_2O. CO_2 accounts for most of GHG emissions from stationary combustion and in the U.S. represent around 99 percent of the total CO_2e GHG emissions. CH_4 and N_2O represent around 1 percent of GHG emissions in the U.S. There are two methods to estimate CO_2 emissions from stationary combustion sources: (1) Direct measurement and (2) Analysis of fuel input.

The direct measurement of CO_2 is done through the use of a Continuous Emissions Monitoring System (CEMS), this system has two approaches: (1) Determine the CO_2 mass emissions by performing a monitor measuring of the percentage of CO_2 per volume of flue gas and a monitor measuring of the volumetric flow rate of flue gas. The annual CO_2 emissions are calculated taking into account the operating time of the unit; or (2) Perform a monitor measuring of the percentage of O_2 per volume of flue gas and a monitor measuring of the volumetric flow rate of flue gas, then use a theoretical CO_2 and flue gas production factors by fuel characteristics to calculate CO_2 flue gas emissions and CO_2 mass emissions. The annual CO_2 emissions are calculated taking into account the operating time of the unit.

The analysis of fuel input approach implies determining the carbon content of the fuel burned and applying that to the amount of fuel combusted to get CO_2 emissions. The default approach is to use carbon content factors that are based on energy units instead of mass or volume units since carbon content factors based on energy units are less variable than carbon content factors based on mass or volume units so there is less chance for error. Equation 2 presents the default fuel analysis method.

[17] http://www.epa.gov/climateleaders/documents/cl_programguide_508.pdf

Equation 2 Fuel Analysis Approach[18]

$$\text{Emissions} = \sum_{i=1}^{n} \text{Fuel}_i \times \text{HC}_i \times \text{C}_i \times \text{FO}_i \times \frac{\text{CO}_{2\,(\text{m.w.})}}{\text{C}_{(\text{m.w.})}}$$

where:

Fuel_i	=	Mass or Volume of Fuel Type i Combusted
HC_i	=	Heat Content of Fuel Type i $\left(\frac{\text{energy}}{\text{mass or volume of fuel}}\right)$
C_i	=	Carbon Content Coefficient of Fuel Type i $\left(\frac{\text{massC}}{\text{energy}}\right)$
FO_i	=	Fraction Oxidized of Fuel Type i
CO_2 (m.w.)	=	Molecular weight of CO_2
C (m.w.)	=	Molecular Weight of Carbon

Equation 3 presents the basic procedure to calculate CH_4 and N_2O emissions from stationary combustion. These emissions depend on the characteristics of the fuel, the technology type, the combustions characteristics and the control technologies. The emission factor is used to determine the amount of CH_4 and N_2O emissions in relation with CO_2 emissions.

Equation 3 CH_4 and N_2O Emissions Estimation Method[19]

$$\text{Emissions}_{p,s} = A_s \times EF_{p,s}$$

where,

p	=	Pollutant (CH_4 or N_2O)
s	=	Source Category
A	=	Activity Level
EF	=	Emission Factor

2.2 Project-Specific GHG Accounting Protocol

The Clean Development Mechanism (CDM) uses a project specific approach for GHG project evaluation. This case specific approach is designed to ensure that environmental objectives are

[18] Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, March 2008. Direct Emissions from Stationary Combustion Sources. www.epa.gov/climateleaders

[19] Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, March 2008. Direct Emissions from Stationary Combustion Sources. www.epa.gov/climateleaders

achieved, but also as a screen to determine if carbon offset funding will enhance project economics to the point that the project becomes viable. Following are summaries of the two approved CDM methodologies for boilers:

- ***Methodology AM0044:*** Energy efficiency improvement projects: boiler rehabilitation or replacement in industrial and district heating sectors (valid from December 22, 2006 onwards)[20]. This methodology is applicable to projects in any region, aiming at efficiency improvement by replacing or rehabilitating small capacity boilers for thermal power generation systems (hot water or low pressure steam) for district heating or industry. The methodology only covers CO_2 emissions The CDM methodology determines that methane and nitrous oxide emissions are insignificant for project accounting purposes.

  AM0044 also assumes no significant leakage is expected for this type of project and that leakage can be ignored.

  One of the aspects of additionality in this methodology is a common practice test. If more than 33 percent of the control group uses improved boilers that are similar to the project activity, then the project is not additional. The control group is defined as plants, factories and/or buildings where thermal energy is generated for internal use or for sale to surrounding customers, excluding the projects implemented under the CDM, in the region where the project is located. The region of the control group is defined as the geographic area around the project activity that has similar legal compliance requirements as for the project activity.

  Also for the additionality determination, the Internal Rate of Return (IRR) has to be estimated and compared against alternatives. The IRR must be demonstrated to be lower than the most likely or benchmark alternative.[21]

  The emissions calculation method is the following:

Equation 4 Project Emissions Calculation[22]

$$PE_{i,y} = FC_{PJ,i,y} \cdot NCV_i * EF_{C,FF,i} \cdot OXID_{FF,i} \cdot 44/12$$

$PE_{i,y}$	=	Emissions from fossil combustion at project boiler 'i' in year 'y' (tCO_2/yr).
$FC_{PJ,i,y}$	=	Fossil fuel consumption at project boiler 'i' in year 'y' (mass of volume units/yr).
$EF_{C,FF,i}$	=	Emission factor for the fossil fuel used in the project boiler 'i' (tC/MJ).
NCV_i	=	Net calorific boiler of fossil fuel used in the project boiler 'i' (MJ/mass or volume units)
$OXID_{FF,i}$	=	Oxidation factor for the fossil fuel used in the project boiler 'i' (fraction).

Methodology AM0056: Efficiency improvement by boiler replacement or rehabilitation and optional fuel switch in fossil fuel-fired steam boiler systems (valid from July 27, 2007 onwards). This methodology deals with the same project type as the AM0044 methodology mentioned above, but in addition covers project activities that deal with fuel

[20]http://cdm.unfccc.int/UserManagement/FileStorage/CDMWF_AM_L4AQZSBA770KNI0BUSG1JVIWCXIFU5
[21] http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf
[22] http://cdm.unfccc.int/UserManagement/FileStorage/CDMWF_AM_L4AQZSBA770KNI0BUSG1JVIWCXIFU5

switching and steam condensate return. This methodology follows the same overall accounting procedures as AM0044 and is considered an extension of the AM0044 methodology[23].One important is that leakage is specifically addressed in AM0056. The methodology states that leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. In this methodology, the following leakage emission sources are to be considered:

• Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, regasification and distribution of natural gas used in the project activity and fossil fuels used in the absence of the project activity.

• In the case LNG is used in the plant: CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

In essence, this methodology attempts to address the life cycle GHG aspects of natural gas fuels, recognizing that generation and delivery systems for fuels can result in significant emissions. This has parallels to the US EPA Climate Leaders program, which addresses natural gas fugitive emissions, but actually goes further by specifying LNG generation and transportation emissions.

EPA Climate Leaders common approach to calculate direct emissions is based on multiplying purchased quantities of commercial fuels by a documented emission factor, this method is more market oriented. In the case of a project under the CDM scheme, direct emissions are calculated on a project-by-project basis, which reduces the sources of uncertainty in the calculations.

3 Performance Standard Development

In this section, we highlight specific issues that need to be considered when developing a protocol that covers increasing the efficiency of boilers.

The objective of a boiler efficiency project protocol is to develop a methodology to quantify a reduction of GHG emissions that is attributed to boiler systems. Boiler system improvements can be realized through boiler retrofit projects by the addition of economizers, air and water pre-heaters, exhaust steam heat recovery, improved combustion techniques and improved controls. In addition, the heating process can be made more efficient by insulating distribution piping, more efficient pump motors, and/or replacing and maintaining steam traps. In addition, the protocol needs to address the type of boilers that are addressed (e.g. oil, natural gas, and electric) and will likely require a separate protocol for each energy source.

Industrial Boilers

Industrial boilers are not generally purchased as an “off-the-shelf” item that one simply selects based on the manufacturer’s performance label. Manufacturers have models that they will construct given the specification provided by an engineer. From a performance perspective, the

[23]http://cdm.unfccc.int/UserManagement/FileStorage/CDMWF_AM_XSQZ9OTPYIVL9O1AUDP7PV1JGX2WBJ

engineer will specify the desired design output capacity, steam pressure and temperature requirements, and emission thresholds that the boiler must meet. For example, the engineer may indicate that the required nitrogen oxides (NOx) emission threshold is at a level such that a low NOx version of the boiler is required, or that the new boiler must be guaranteed to meet carbon monoxide (CO) emission limits (as a surrogate for organic hazardous air pollutants) for compliance with the National Emission Standards for Hazardous Air Pollutants (NESHAP). The boiler manufacturer will then apply the correctly sized boiler components to their boiler design and engineered specifications before running a computer model to estimate the resulting operational characteristics, including thermal efficiency and emissions of the resulting boiler. For these reasons, the design efficiency of industrial boilers is relatively narrow and there are no "standard efficiency" and "high efficiency" versions of similar industrial boilers. In general, industrial natural gas-fired boilers producing steam have thermal efficiencies of 75% - 83%.[24]

However, in some cases, selecting higher performance burners and integrating more sophisticated controls can increase the efficiency of industrial boilers. Some of these technologies are standard practices while others are not commonly used. Therefore, an industrial boiler protocol is best suited for a technology-based approach. This type of approach focuses on improving the efficiency of boilers used for industrial process applications by adding advanced technologies (such as advanced heat recovery, controls and burners) to the boiler system. These technology-based efficiency improvements can be achieved when retrofitting or replacing an existing boiler with new boiler technology, when purchasing a boiler to meet new demand, and/or when fuel switching.

The technology options described below are not commonly used and could potentially be used for a GHG offset project. The list of technologies is not exhaustive and other emerging technologies such as those being studied in the DOE "Super Boiler" program are also potentially eligible.

- ***Non-condensing Economizer (Conventional stack heat recovery):*** This device recovers heat from the boiler exhaust and is used to pre-heat the boiler feed water. This reduces the load on the boiler as the temperature differential of the feed water in the boiler is reduced. Typically, for each 10 ^{o}F increase in feed water temperature, the boiler thermal efficiency increases by 1%.[25] Non-condensing economizers are considered standard on industrial applications as the pay back can be less than a year.[26] Typical applications increase natural gas boiler efficiencies by 5%.[27]

- ***Condensing Economizer (Condensate heat recovery):*** This device performs the same function as the non-condensing economizer with the difference that it extracts more heat from the exhaust stream thereby providing for a higher inlet feed water temperature. By cooling the exhaust air to the point of condensation, the latent heat of exhaust is captured. This economizer can increase the natural gas boiler efficiency by 7% - 8%.[28] The

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[24] http://alliantenergy.com/docs/groups/public/documents/pub
[25] www.eere.energy.gov boiler check list
[26] Interview – December 20, 2005: Aaron Sink, Engineering Support, Cleaver Brooks (402) 434-2017
[27] www.neboiler.com/Economizer
[28] http://alliantenergy.com/docs/groups/public/documents/pub

drawback of this approach is that the condensed matter is very corrosive so the economizer requires special materials.[29] The typical payback for the condensing economizer is approximately 5 years which is also the approximate lifetime of the economizer before it has to be replaced. The use of condensing economizers is not a standard practice.

- ***Combustion Air Pre-heaters (Recuperators):*** This device preheats the incoming combustion air. This reduces the load on the boiler by reducing the energy needed to heat the air from ambient. The heat source can be from an economizer, air at the boiler room ceiling or other heat recoverable source. Typically, for each 40 ^{o}F increase in combustion air temperature, the boiler thermal efficiency increases by 1%.[30] Application of this device needs to be coordinated with the boiler manufacturer to ensure that it does not negatively impact performance or create a hazardous situation. In addition, the fan capacity may need to be increased to ensure the appropriate quantity of air is being delivered. Recuperator use is dependent on the boiler application and its impact is greater in colder regions of the United States. The use of combustion air pre-heaters is not standard practice.

- ***Blowdown Waste Heat Recovery:*** Heat is recovered from boiler blowdown through a heat exchanger and a flash tank. Blowdown heat exchangers are typically used to pre-heat boiler make-up water and the flash tank recovery can be used in the deaeration or other heating process. Blowdown heat recovery can increase boiler system efficiency by about 1%.[31] The use of blowdown heat recovery systems is not a standard practice.

- ***Turbulators (Example of Advanced Burner):*** These are essentially twisted pieces of metal inserted in the tubes of fire-tube boilers, causing hot gases to travel more slowly and with more turbulence, resulting in better heat transfer to the water. The use of turbulators is not standard practice.

- ***Oxygen Trim Controls (Example of Advanced Combustion Control):*** These controls measure stack gas oxygen concentration and automatically adjust the inlet air at the burner for optimum efficiency. The use of oxygen trim controls is not standard practice.

The following table presents a summary of the energy efficiency measures for industrial boilers installed in California as of 2003[32]. The data shows that stack heat recovery, condensate heat recovery and electronic ignition options are installed on 20% - 30% of existing industrial boilers in California. All other options as presented above are considered to be beyond business as usual and not a standard practice for the industry.

[29] http://eereweb.ee.doe.gov/industry/bestpractices/pdfs/steamsourcebook.pdf
[30] Boiler Efficiency Institute, Boiler Efficiency Improvement
[31] http://alliantenergy.com/docs/groups/public/documents/pub
[32] Non Residential Market Share Tracking Study, California Energy Commission, April 2005CEC 400-2005-013

Table 6 Industrial Gas Boiler Energy Efficiency Measures in California (2003) - SICs 21-34, 37-39

Measures on Existing Boilers	
Stack Heat Recovery	22.2%
Condensate Heat Recovery	20.9%
Other Heat Recovery	7.5%
Automated tuning (O_2 trim control)	13.8%
Electronic ignition	31.1%
Turbulators for firetube boilers	9.9%
Boiler and System Retrofits in Prior 3 Years	
Stack Heat Recovery	10.7%
Condensate Heat Recovery	3.0%
Other Heat Recovery	0.0%
Automated tuning (O_2 trim control)	1.9%
Electronic ignition	11.8%
Turbulators for firetube boilers	0.7%
Increased pipe and jacket insulation (system EE)	22.1%
Reduced boiler blow-down cycle (system EE)	3.6%
Reduced steam pressure (system EE)	37.6%
Variable speed drives on fans (system EE)	2.4%
Automatic flue damper (system EE)	4.3%
Smaller boiler for low load conditions (system EE)	0.7%
Other	0.2%

Commercial Boilers

A commercial boiler protocol is well suited for a (emissions performance-based) standard rated efficiency approach. This type of approach focuses on the engineer or building owner selecting and installing a high efficiency boiler that exceeds a certified threshold limit. Commercial boilers have rated efficiencies that are based on a standardized performance testing protocol. The federal government and some states have minimum efficiency requirements for boilers that can be made available in the market. In addition, Energy Star has established a threshold for efficiency that that a boiler must meet in order to qualify as an Energy Star appliance.

The following table presents the minimum commercial boiler energy efficiency requirements as published in ASHRAE 90.1.

Table 7 Minimum Commercial Boiler Efficiency as Published by ASHRAE 90.1

Gas- and Oil-Fired Boilers–Minimum Efficiency Requirements

Equipment Type[d]	Size Category (Input)	Subcategory or Rating Condition	Minimum Efficiency[a]	Test Procedure[b]
Boilers, Gas-Fired	< 300,000 Btu/h	Hot Water	80% AFUE	DOE 10 CFR Part 430
		Steam	75% AFUE	
	≥ 300,000 Btu/h and ≤2,500,000 Btu/h	Maximum Capacity[c]	75% E_t[a]	H.I. Htg Boiler Std.
	>2,500,000 Btu/h[d]	Hot Water	80% E_c	
	>2,500,000 Btu/h[d]	Steam	80% E_c	
Boilers, Oil-Fired	< 300,000 Btu/h		80% AFUE	DOE 10 CFR Part 430
	≥ 300,000 Btu/h and ≤2,500,000 Btu/h	Maximum Capacity[c]	78% E_t[a]	H.I. Htg Boiler Std.
	>2,500,000 Btu/h[d]	Hot Water	83% E_c	
	>2,500,000 Btu/h[d]	Steam	83% E_c	
Oil-Fired (Residual)	≥ 300,000 Btu/h and ≤2,500,000 Btu/h	Maximum Capacity[c]	78% E_t[a]	H.I. Htg Boiler Std.
	>2,500,000 Btu/h[d]	Hot Water	83% E_c	
	>2,500,000 Btu/h[d]	Steam	83% E_c	

a E_t = thermal efficiency. See reference document for detailed information.
b Section 12 contains a complete specification of the referenced test procedure, including the referenced year version of the test procedure.
c Minimum and maximum ratings as provided for and allowed by the unit's controls.
d These requirements apply to boilers with rated input of 8,000,000 Btu/h or less that are not packaged boilers, and to all packaged boilers. Minimum efficiency requirements for boilers cover all capacities of packaged boilers.

To develop an emission based performance standard, the efficiency information must be combined with the fuel type being used, since fuel oil and natural gas (as well as biomass) have quite different carbon intensities. How this is actually done is detailed in the next section of this report.

Residential Boilers

A residential boiler protocol is also best suited for a (emissions performance-based) standard rated efficiency approach. This type of approach focuses on the engineer or building owner selecting and installing a high efficiency boiler that exceeds a certified threshold limit. Residential boilers have rated efficiencies that based on a standardized performance testing protocol. The federal government and some states have minimum efficiency requirements for boiler that can made available in the market. In addition, Energy Star has established a threshold for efficiency that that a boiler must meet in order to qualify as and Energy Star appliance.

The following tables present the DOE minimum performance requirements for residential boilers. Data is presented for boilers manufactured prior to 2012 and then the standard after 2012.

Table 8 Residential Boilers AFUE manufactured before September 1, 2012

Product Class	AFUE (%)
(A) Boilers (excluding gas steam)	80
(B) Gas steam boilers	75

Table 9 Residential Boilers AFUE manufactured on or after September 1, 2012 and Design Requirements

Product Class	AFUE (%)	Design Requirements
(A) Gas-fired hot water boiler	82	Constant burning pilot not permitted. Automatic means for adjusting water temperature required (except for boilers equipped with tankless domestic water heating coils)
(B) Gas-fired steam boiler	80	Constant burning pilot not permitted
(C) Oil-fired hot water boiler	84	Automatic means for adjusting temperature required (except for boilers equipped with tankless domestic water heating coils)
(D) Oil-fired steam boiler	82	None
(E) Electric hot water boiler	None	Automatic means for adjusting temperature required (except for boilers equipped with tankless domestic water heating coils)

ENERGY STAR qualified boilers have an AFUE rating of 85% or greater. They achieve greater efficiency with improved features, including:

- Electric ignition, which eliminates the need to have the pilot light burning all the time
- New combustion technologies that extract more heat from the same amount of fuel
- Sealed combustion that uses outside air to fuel the burner, reducing draft and improving safety

As is the case for commercial boilers, to develop an emission based performance standard, the efficiency information must be combined with the fuel type being used, since fuel oil and natural gas (as well as biomass) have quite different carbon intensities. How this is actually done is detailed in the next section of this report.

4 Additionality - Relevant Regulations, Voluntary Initiatives and Barriers

4.1 Relevant Regulatory Developments

This section explores Federal and State requirements that would affect eligibility of GHG offsets from boilers. At a minimum, offsets must do more than just comply with laws and regulations pertaining to their use. To start with, the Federal government has for many years had minimum efficiency standards for boilers. Boiler operational efficiencies are tested prior to being sold; each model is assigned an AFUE rating. These standards for residential and commercial boilers were cited previously. Surprisingly, there are no current minimum Federal efficiency requirements for industrial boilers.

In November 2007, the US DOE published updated federal efficiency standards for residential furnaces and boilers. Table 10 contains the minimum efficiency requirements that will apply to products manufactured in - or imported to- the U.S on or after November 19, 2015.

Table 10 Minimum Efficiency Requirements for Products on or after November 19, 2015

Product Class	AFUE (%)
Gas-fired hot water boiler	82
Oil-fired hot water boiler	84

Additionally, some state and local governments may have efficiency standards that were reviewed. In the case of California, the California Energy Commission (CEC) recently adopted the 2008 Building Energy Efficiency Standards (California Building Standards Code, Title 24). The new standards will take effect on August 1, 2009. Table 11 presents these minimum efficiency requirements. Note that as discussed above, the AFUE efficiency standard is based on the DOE testing protocol for boilers less than 300,000 BTU/hr while boiler of greater capacity fall under other testing protocols for efficiency ratings.

Table 11 Minimum Heating Efficiency for Boilers

Appliance Type	Rated Input (BTU/hr)	Minimum Efficiency (%)	
		AFUE	Combustion Efficiency at Maximum Rated Capacity
Gas Steam boilers with single phase electrical supply	< 300,000	75.0	—
All other boilers with single phase electrical supply	< 300,000	80.0	—
Gas packaged boilers	≥ 300,000	—	80.0
Oil packaged boilers	≥ 300,000	—	83.0

The American Counsel for an Energy Efficient Economy (ACEEE) conducted a study in 2006[33] to investigate the impact of increasing national efficiency standards. The findings for commercial and residential boilers are presented in the following tables. The study looks at increasing the current efficiency standards to those stated in the tables. For commercial boilers,

[33] ACEEE, Leading the Way Report # ASAP-6/ACEEE-A062, March 2006

the study is based on an 81percent overall efficiency where the current standard is based on a combustion efficiency so the analysis corresponds to an increase in overall efficiency by 2 percent – 3 percent.

Table 12 Economics for a Higher Commercial Boiler Efficiency Standard

Standard: Overall Efficiency (%)	81%
Cost Differential ($)	$2,968
Annual Savings	
Therms	514
$	$514
Assumed Equipment Life (years)	30
Benefit to Cost Ratio	3.6
Simple Payback (years)	5.8

The following table presents the results for a higher residential boiler standard for both natural gas and oil-fired boilers. The analysis is for an efficiency (AFUE) of 84% and shows that the marginal cost of the higher efficiency units is modest.

Table 13 Economics for a Higher Residential Boiler Efficiency Standard

	Natrual Gas Boiler	Oil-Fired Boiler
Standard: AFUE (%)	84%	84%
Cost Differential ($)	$114	$29
Annual Savings		
Therms	32	
Gallons		30
$	$39	$63
Assumed Equipment Life (years)	25	25
Benefit to Cost Ratio	4.7	30.6
Simple Payback (years)	3.0	0.5

These proposed standards are less than a performance standard that would be developed for a threshold for additionality, but provides some insight into the relative economics of higher efficiency systems. The payback for the commercial case is 5.8 years. Since commercial entities typically invest in projects that have a payback of less than 5 years and in some cases less than 3 years, this indicates that an incentive might entice commercial customers to make an investment in the higher efficiency product. The payback for residential boilers is 3 years for natural gas units and .5 years for oil-fired units. This indicates that an incentive might not be required to entice residential customers to make an investment in the higher efficiency product.

4.2 Other Regulatory Issues

AB 32 calls on California to reduce its GHG emissions to 1990 levels by 2020. The California Air Resources Board prepared a scoping plan to achieve the objectives stated in AB 32. This plan was approved December 12, 2008 and it includes both new and existing measures in every sector of California's economy. The initiatives include implementing a cap-and-trade program on carbon dioxide emissions by 2012 (which is being developed in conjunction with the Western Climate Initiative, to create a regional carbon market), requiring buildings and appliances have higher energy efficiency standards, lower carbon transportation fuels, and utilities to provide a third of their energy from renewable sources like wind, solar and geothermal power. The scoping plan indicates that industrial boilers > 10 MMBtu/h will generally be under emissions caps[34] in 2012, although the specific threshold for inclusion in the cap cited in the scoping plan is 25,000 tons of emissions from the industrial source.

As mentioned above, the WCI states are working together to develop a regional cap-and-trade program that will begin operations in 2012. The goal is to reduce GHG emissions by 15 percent below 2005 levels by 2020. One of the sectors that is specifically mentioned as being covered in the cap is the natural gas combustion sector, which would include all natural gas-fired boilers (industrial, residential, commercial) by 2015. This would amount to a regulatory mandate covering all fuel combustion by 2015, at which point offsets would not be considered additional from fossil fuels combusted in boilers. This cap would not cover biomass boilers however. These would remain additional from a regulatory standpoint. The AB 32 Scoping Plan also calls for a similar expansion of the cap and trade program in 2015 that would include all natural gas-fired boilers.

4.3 Voluntary Initiatives

Voluntary programs rely on the consumer to buy cleaner burning and more efficient units. Initiatives such as rebates and tax credits, when set at high enough levels, do have an influence on the choice of equipment used. Utility rebate programs for high efficiency industrial boilers are concentrated in a few states in the Northeast, North, and West, and can amount to 25 percent or more of the installed cost. These programs don't appear to be commonplace; Table 14 shows examples of existing initiatives and indicates only a few states are aggressively pursuing rebates for boilers, so this should not be used as a basis for broad performance standards. Rather, GHG offsets will further incentivize the voluntary installation of higher efficiency equipment.

[34] Climate Change Proposed Scoping Plan Appendices, October 2008. Volume II: Analysis and Documentation, p. H-123

Table 14 Boiler Efficiency Rebate Programs

Eligible Equipment	AFUE (%)	Rebate	Sector	Company
Natural gas-fired hot water boiler[35]	≥ 85 ≥ 90	$500 $1,000	Residential	GasNetworks/ Massachusetts
Indirect water heater attached to a natural gas-fired boiler[36]		$300	Residential	GasNetworks/ Massachusetts
Replacement of natural gas-fired boiler that meet or exceed federal Energy Star standards[37]	≥ 85	$500	Residential	State of Connecticut
Replacement of propane or oil furnaces or boilers[38]	≥ 84	$500	Residential	State of Connecticut
Gas-fired hot water boiler (300 < x > 1,000 kBtu/hr) [39]	85 ≤ x ≥ 90	$600 - $3,500	Commercial/ Industrial	NYSERDA/ New York
Natural gas-fired boiler[40]	90	$400	Residential	Avista/ Washington
Oil and gas-fired boilers[41]	≥ 84	$0.50/ MBtuh	Commercial	Sempra Energy/ California
Process boilers[42]	≥ 82	$0.50/ MBtuh	Industrial	Sempra Energy/ California
Natural gas boiler[43]	85 ≤ x >91	$100- $400	Residential	Alliant Energy/ Minnesota
Water Process Boiler[44]	82	$2.00/ MBtuh	Industrial	PG&E/ California
Large Domestic Hot Water Boiler[45]	84	$1.50/ MBtuh	Commercial	PG&E/ California
Space Heating Water Boiler[46]	≥ 82	$1.00/ MBtuh	Residential	PG&E/ California

The Consortium for Energy Efficiency (CEE) launched a high efficiency residential gas heating initiative in 1998[47] with the idea that participating utilities and program administrators can

[35] Source: http://www.gasnetworks.com/efficiency/pdf/GN-Rebate-dynamic.pdf
[36] Ibid
[37] Source: http://www.ct.gov/opm/cwp/view.asp?A=2994&Q=420476
[38] Ibid
[39] Source: http://www.nyserda.org/Programs/SWP/nationalfuel.asp
[40] Source: http://www.greenmadesimple.com/incentives/details/avista-home-improvement-rebates
[41] Source: http://www.socalgas.com/business/rebates/er_express_rebates.html
[42] Source: http://www.socalgas.com/business/rebates/er_express_rebates.html
[43] Source: http://www.alliantenergy.com/docs/groups/public/documents/pub/p015689.pdf
[44] Source: http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/rebatesincentives/08boilerswaterheating.pdf
[45] Ibid
[46] Ibid

promote the use of higher efficiency equipments (boilers and furnaces) through rebate programs and/or consumer and contractor education about the benefits of efficient gas heating equipment. When this program began, only 12 percent of the furnaces available in the market met CEE's efficiency standards. In 2005, 30 percent of the available equipment met CEE's standards. The utilities currently participating in this initiative are: Aquila, Bay State Gas, Berkshire Gas, Efficiency Vermont, Energy Trust of Oregon, Gaz Métro, MidAmerican Energy, New England Gas Co., N.J. Board of Public Utilities, NSTAR Electric & Gas, Pacific Gas & Electric, Public Service Electric & Gas, Puget Sound Energy, San Diego Gas & Electric, South Jersey Gas, Southern California Gas, Unitil, Vermont Gas Systems, Wisconsin Dept. of Admin and Xcel Energy - Minnesota

The CEE specification for boilers is set at a similar efficiency level than the ENERGY STAR® requirements. The gas furnace specification consists of a fuel-efficiency requirement and a new electricity use option. In 2002, the fuel efficiency specification was updated to reflect advances in technology and changes in market conditions, this specification has three tiers that can be used to promote different levels of efficiency – Gas fired furnaces: Tier 1: 90 percent, Tier 2: 92 percent and Tier 3: 94 percent. CEE's efficiency level for gas-fired boilers is 85 percent.

4.4 Setting a performance standard for additionality

The selection of a performance standard should set an aggressive stretch goal that is significantly beyond business as usual practices. This is typically done by looking at recent market penetration of the technologies being considered for GHG reduction projects and determining the degree to which they are influencing recent purchase decisions. This type of additionality is commonly referred to as technical or technological. In some regimes, financial additionality is also rigorously considered. As noted above, the CDM requires project developers to show on a case-by-case basis that the IRR is at least below average and, combined with other barrier issues, that the project requires the CDM process and funding to proceed. This type of approach does not conform itself to a standardized performance threshold.

In the developed world and the US, financial considerations are normally closely interrelated with the market penetration statistics. Therefore, the information on incentives and economics are provided and explored above to provide further background data on market penetration.

Industrial Boilers

As mentioned previously, there are a number of add-on technologies to industrial boilers that can add to the base boiler efficiency and reduce GHG emissions. Table 6 above showed the recent deployment of these technologies in a California survey. Essentially, technologies that were deployed in the prior 3 years that were used less than 10% of the time were selected here (and in EPA Climate Leaders) for eligibility as add-on technologies that would be eligible for GHG credits. RGGI market penetration rate (MPR) criteria for boilers are generally set at 5% of recent activity (RGGI does not define what "recent" means), whereas some CDM methodologies suggest a 33% rate as a cutoff. EPA Climate Leaders is somewhere in between – typically the top

[47] http://www.cee1.org/resrc/facts/gs-ht-fx.pdf

10 to 20 percent of recent activity. However, we will see below that the RGGI MPR isn't well aligned with their performance standard for boilers.

Commercial Boilers

Using a standard rated efficiency threshold for commercial boilers requires looking at the market and identifying the target threshold that represents a clear break from standard practice. The Consortium for Energy Efficiency (CEE) reports that the rate of high efficiency boilers (≥ 85%) has gone from 5-15% of sales in 2002 to 50%-60% of sales in 2007.[48] The same study indicates that condensing boiler sales have risen from 2% in 2001 to between 20 and 25% in 2007. These data indicate that a threshold of 85% is too low. The CEE study noted that commercial boilers can be classified in the following tiers of efficiency and technology. In essence, technical improvements can be made to existing boiler types to improve efficiency to 88%. Above 88%, the technology required to achieve this level of efficiency is the condensing boiler.

Table 15 Natural Breakpoints in Commercial Boiler Performance

Efficiency Level	Technology
80-84%	Atmospheric
85-88%	Fan assisted, non-condensing
88-98%	Fan assisted, condensing

The reasons for this significant increase are higher fuel prices, the Federal tax incentive from EPACT 2005, and utility rebate programs. Utility rebate programs were noted above, but it is important to note that these programs do not help boilers in many areas of the country. The Federal tax incentive is probably more of an incentive. The Energy Policy Act of 2005 (EPACT 2005) provides a federal tax deduction of up to $1.80 per square foot to owners of new or existing commercial buildings that save at least 50% of the heating and cooling energy of a building that meets ASHRAE Standard 90.1-2001. Partial deductions of up to $.60 per square foot can be taken for measures affecting any one of three building systems: the building envelope, lighting, or heating and cooling systems.

Recent fuel price decreases are expected to have slowed sales of higher efficiency boilers, as the costs of condensing boilers are typically 50-70% greater than conventional boilers. This would lend credence to a performance standard in the area of 88-90% for commercial boilers since market penetration has most likely dropped below 20% now.

[48] "**Market Characterization of Commercial Gas Boilers", CEE Winter Program Meeting,** January 16-17, 2008 Long Beach, California

The CEE study also notes a barrier that the commercial boiler market experiences – the owners of commercial buildings are often the landlords who rent out space to tenants. These tenants frequently look for the lowest price in floor space and are not motivated by long term energy savings when the length of their lease it short. For this reason, owner-occupied buildings are nearly twice as likely to have an upgrade to a condensing boiler as non-owner occupied.

Residential Boilers

Using a standard rated efficiency threshold for residential boilers requires looking at the market and identifying the target threshold that represents a significant move toward GHG reductions. Shipments of residential Energy Star boilers (efficiency > 85%) and an estimated market penetration for 2006 are presented in the following table[49]

Table 16 Market Penetration for Energy Star Rated Residential Boilers (2006)

Type of Boiler	Units Shipped (2006)	Market Penetration
Residential Gas Boilers	68,102	34%
Residential Oil Boilers	314,668	67%

Similar to the commercial data, the high efficiency boilers are becoming more commonplace in the market. Utility rebate programs are given as one reason, but high fuel prices are also a key driver. Residential gas boilers that are currently available in the market have AFUE efficiencies ranging from 80% to 99% with the units in the high 90% range being condensing boilers. Residential oil boilers that are currently available in the market have AFUE efficiencies ranging from 80% to 90%[50].

An approach for selecting a performance standard for boilers is to look at the distribution of sales by efficiency rating. A summary of shipments for 2001 as reported by DOE illustrate the distribution. The following figures present the distribution of efficiencies of residential boilers in 2001[51].

[49] Energy Star Unit Shipment and Market Penetration Report – Calendar Year 2006 Summary
[50] http://aceee.org/consumerguide/heating.htm
[51] http://www1.eere.energy.gov/buildings/appliance_standards/residential/printable_versions/fb_nopr_analysis.html

Figure 3 Efficiency of Residential Gas Boilers Shipped in the US in 2001

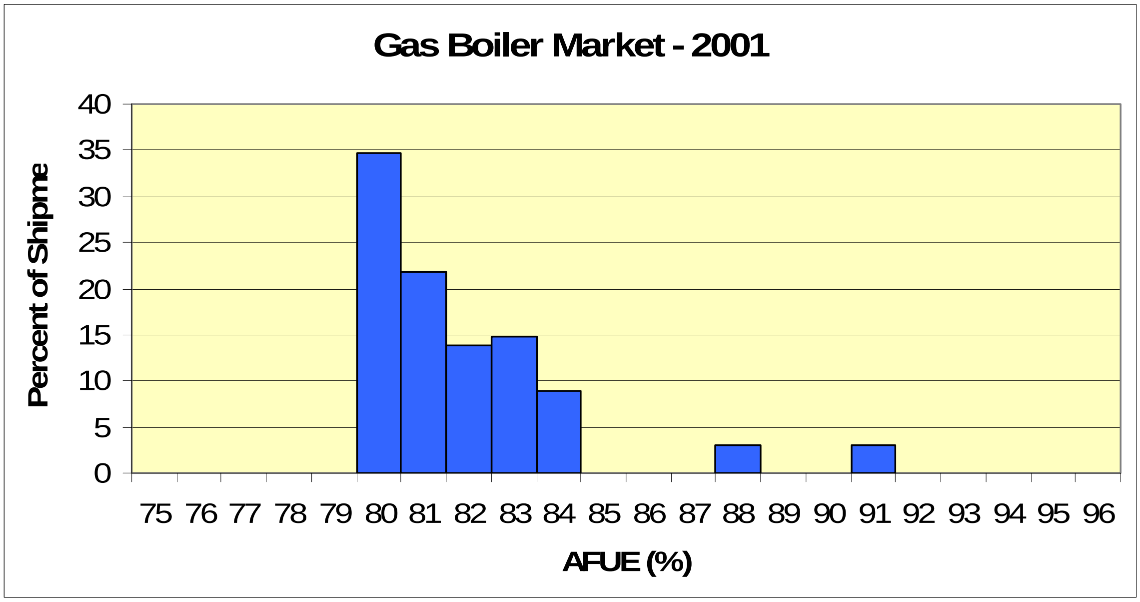
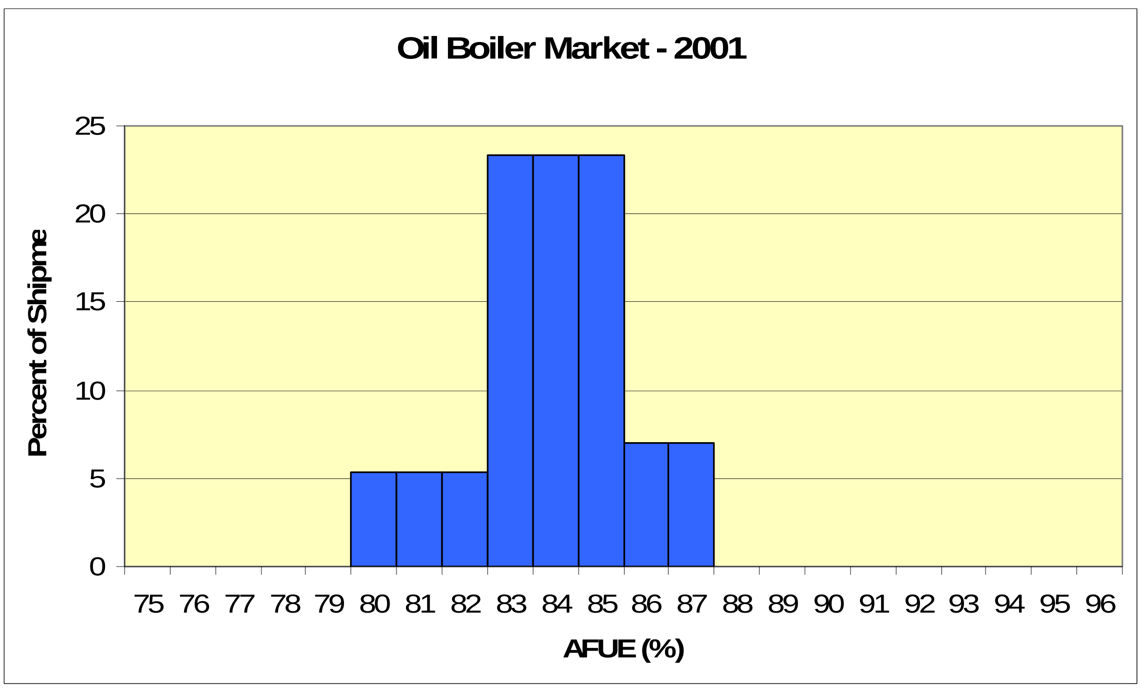


Figure 4 Efficiency of Residential Oil Boilers Shipped in the US in 2001



In the graph of the gas boilers, there is a distinct segregation of boilers at the 88% and then the 91% level. Based on this data, these would have been good candidates for a threshold efficiency for the gas boilers in 2001. In the case of the oil boilers, the distinction is not as dramatic, however the data does show that the top 7% of oil boilers had an efficiency of 87%, which could be considered as a threshold efficiency.

CEE has released some more recent information pertaining to shipments of high efficiency residential boilers and furnaces. A 2007 study[52] indicates that nearly 1/3 of recent boiler shipments met or exceeded their program's requirements – namely boilers of 85% or greater efficiency (same as EPA Energy Star) and furnaces with 90% or better AFUE. Although more specific data could not be located for this study, this would suggest that a residential boiler performance threshold should be set higher than 85%, since this is 30% of the market. However, cutoffs for 20% and 10% can't be precisely determined at this time. If we assume that 40% of these high efficiency boilers are condensing types (above 90% efficiency), a 90% performance threshold would represent the top 12% of performance. The 40% assumption comes from the current split of condensing to non-condensing boilers seen in the commercial sector.

RGGI has selected a performance standard for commercial boilers according to the following table.

Table 17 Commercial Boilers Performance Standard

Gas-fired[a]	125,000-300,000	AFUE	≥88.0%
	300,000-12,500,000	Thermal Efficiency[b]	≥90.0%
Oil-fired	>300,000	Thermal Efficiency	≥88.0%

As was mentioned earlier, this performance standard does not conform to their 5% MPR criteria. The CEE study cited above would suggest that these are closer to a 20-25% MPR criteria. RGGI has also selected a performance standard of 90% AFUE for residential boilers. As was noted in the preceding paragraph, this level may represent the top 12% of market activity.

5 Baseline Quantification – Combining efficiency information with fuel use options

To determine baseline emissions for boilers, one must consider not only the efficiency of the boiler that would have been expected to be placed into service, but also the fuel that would be expected to be used. The fuel that would be expected to be used will vary and will depend on whether the project involves the retrofit of an existing boiler or new construction. Differences arise because retrofit decisions are different than new equipment decisions. Retrofits are usually made to keep the same fuel source since a new fuel source and fuel lines can be cost prohibitive.

[52] CEE's High-Efficiency Residential Gas Heating Initiative – 2007 http://www.cee1.org/resrc/facts/gs-ht-fx.pdf

Here it is important to discuss some notable differences between baseline calculation approaches. RGGI and EPA Climate Leaders both offer standardized baseline calculations. RGGI's approach for boilers is much simpler. RGGI requires that the baseline emissions are based on the assumed minimum energy performance required by applicable building codes or equipment standards shall be that which applies to new equipment that uses the same fuel type as the equipment being replaced. This would amount to an 80% combustion efficiency requirement of ASHRAE for commercial boilers and 80% AFUE for residential boilers noted in Table 7. In 2012, these requirements will be raised slightly for residential boilers as noted in Table 9.

EPA Climate Leaders takes a different approach. For commercial and industrial boilers, they set their baseline emissions calculation actually at the performance threshold level (e.g. 84% for natural gas fired commercial boilers). The philosophy here is that the offset program should assume for conservativeness reasons that the baseline emissions are a better than average decision made by the project developer. This contrasts with the RGGI approach, which essentially assumes the baseline is a minimum, or below average decision made by the project developer and is questionable from a conservativeness perspective. It should also be noted that the CDM baseline calculations are not standardized and are project specific determinations. These determinations involve looking at a suite of alternatives and selecting the most likely as a baseline.

Further discussion of emission baselines are presented below:

1. Retrofit. For projects involving the retrofit or early replacement of a boiler, the baseline should be equal to the average annual emissions of the existing boiler for the remainder of the boiler's estimated remaining useful life and then the differences between the installed boiler and the project threshold in the year in which a new boiler would have been installed. The estimated useful life of the various types of boilers are as follows:

- Industrial Boilers: 20 – 40 years[53]
- Commercial Boilers: The following table presents the values as estimated by ASHRAE[54]

Table 18 Commercial Boilers Estimated Useful Life

Boiler Type	Hot Water Service (years)	Steam Service (years)
Steel Water Tube	24	30
Steel Fire Tube	25	25
Case Iron	35	30
Electric	15	N/A

[53] *Characterization of the U.S. Industrial Commercial Boiler Population*, Oak Ridge National Laboratory, May 2005

[54] ASHRAE – HVAC Applications Handbook, Owning and Operating Costs

- Residential Boilers: 25 years (ASHRAE[55])

2. New Capacity.

Fuel choice for new boilers will depend on the category of boiler being considered.

For industrial boilers, the MECS 2002 survey conducted by the Energy Information Administration includes data on all market fuels and electricity used by industrial boilers, but excludes by-product fuels. The MECS 2006 survey is being processed, but has not yet been released. The survey showed that in 2002 natural gas was the predominant fuel regardless of region or location, representing 78% of the total fuel consumed by industrial boilers. Coal made up another 15% and fuel oil about 6%. Recent engineering practices in states such as California, Wisconsin, and New York indicate that use of natural gas is even more prevalent in industrial boilers that have been installed within the past 5 years. This is because industry has switched to natural gas in new boilers to meet the CAA and NESHAP regulations and the associated NOx, SO2, and PM standards. For example, the CEC Non Residential Market Share Tracking Study shows that 100% of new industrial boiler applications installed in the years 2000-2002 used natural gas as the primary fuel, although they often had dual fuel burners to burn diesel in the event of a natural gas supply disruption.[56] Thus, an assumption of natural gas as the baseline fuel for new industrial boilers is recommended.

For projects involving new commercial and residential boilers, or the replacement of the boiler at the end of its lifetime the project developer or resident will have a choice of fuel options depending on regional supplies, costs, and existing environmental regulations relevant to the use of natural gas, fuel oil, and electricity. It is appropriate then to develop regional performance thresholds and emission baselines that take into account the typical energy mix for boilers in that region as well as individual boiler performance. Developing an emissions baseline in this manner will create regional thresholds that can vary considerably between the Northeast, where there is the highest fuel oil use in commercial and residential boilers and the Midwest and West, where there is the highest natural gas use.

There are two different ways to develop baseline emission calculations for new boilers, and they yield different results. The first approach considers all commercial buildings, regardless of age, with information extracted from CBECS 2003. A similar approach can be used for residential boilers using RECS 2005 data. The approach used in Table 19 essentially “stacks” boilers from dirtiest to cleanest – with electric boilers being the dirtiest and natural gas being the cleanest. We can say this, since the best fuel oil boilers and electric boilers always have higher GHG emissions than natural gas.[57] Developing an emissions baseline around a 20th percentile of emissions performance (the approach taken in EPA Climate Leaders) results in the following.

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55 ASHRAE – HVAC Applications Handbook, Owning and Operating Costs

56 California Energy Commission, Non Residential Market Share Tracking Study, CEC 400-2005-013, April 2005.

57 Analysis shows that the best fuel oil boiler performance (0.0762 tCO2/MMBtu) and the best electric boiler performance (0.0892 tCO2/MMBtu in the Pacific Northwest grid) always result in higher emissions than the minimum required natural gas boiler performance.

Table 19 Commercial boiler baseline example based on emissions-intensity criteria (all CBECS building data, all years)

	Percentage of total regional use in boilers			
	Northeast	Midwest	South	West
Fuel Oil Boilers	24.9%	0.7%	4.1%	1.1%
Fuel Gas Boilers	30.7%	57.9%	36.5%	50.2%
Electric Boilers	44.5%	41.4%	59.4%	48.7%
Total Regional Fuel Oil and Electric Use in Boilers	69.3%	42.1%	63.5%	49.8%
Natural gas use at 20th percentile (i.e., 80% - oil/gas use)	10.7%	37.9%	16.5%	30.2%
Natural gas boiler percentile when total fuel 20th percentile is reached	65.2%	34.5%	54.8%	39.8%
Estimated gas boiler efficiency at 20th percentile	81%	83%	82%	83%
Performance threshold – Baseline Emissions at 20th percentile (tCO2/MMBtu)	0.0655	0.0639	0.0647	0.0639

The above approach did not consider the temporal range of buildings in which commercial boilers are placed. Modern buildings generally use fewer fuel oil boilers and more electric boilers. An emissions baseline can be developed for boilers in buildings constructed since 1990 from CBECS 2003 and is shown in the Table 20. It should be noted that this information was combined using the microfiche data downloaded from the EIA website. Comparable information also exists in RECS for residential units constructed after 1990.

Table 20 Commercial boiler baseline based on emissions-intensity criteria (1990-2003 CBECS data)

	Percentage of regional use in boilers - 1990-2003			
	Northeast	**Midwest**	**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%
Total Regional Fuel Oil and Electric Use in Boilers	57.0%	53.9%	64.4%	56.1%
Natural gas boiler percentile when total fuel top 25th percentile is reached	41.8%	45.7%	29.8%	43.1%
Natural gas boiler percentile when total fuel top 20th percentile is reached	53.5%	56.6%	43.8%	54.5%
Natural gas boiler percentile when total fuel top 10th percentile is reached	76.7%	78.3%	71.9%	77.2%
Estimated gas boiler efficiency at 25th percentile	82%	82%	81%	82%
Estimated gas boiler efficiency at 20th percentile	83%	83%	82%	83%
Estimated gas boiler efficiency at 10th percentile	85%	85%	84%	85%
Emissions baseline at 25th percentile (tCO2/MMBtu)	**0.0647**	**0.0647**	**0.0655**	**0.0647**
Emissions baseline at 20th percentile (tCO2/MMBtu)	**0.0639**	**0.0639**	**0.0647**	**0.0639**
Emissions baseline at 10th percentile (tCO2/MMBtu)	**0.0624**	**0.0624**	**0.0632**	**0.0624**
Weighted average (estimate) (tCO2/MMBtu)	0.1168	0.1497	0.1478	0.1202

When setting the emissions baseline around the top 25th, 20th, or 10th percentile of overall performance, it will represent a fuel gas boiler operating at a below average, average, or above average efficiency, respectively. This approach would be preferred to the first as it is environmentally preferable and since it also better reflects recent trends and fuel choices. The EPA Climate Leaders chose the 20th percentile of overall performance for new boilers in these recent buildings for their performance threshold and is the basis for the baseline emission calculation. This is equivalent to the 84% combustion efficiency standard noted in the Climate Leaders methodology. It is important to note that this will not reward any new oil fired boilers, but will reward more new gas boilers than the RGGI approach.

Once a baseline emission factor is selected, the overall emissions can be determined as follows.

Equations 5, 6 and 7 present the baseline calculation method for retrofits and new capacity boiler efficiency projects under the EPA Climate Leaders program.

Equation 5 Estimated CO_2 Baseline Emissions Retrofits Projects

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 6 Estimated CH_4 and N_2O Baseline Emissions for Retrofits Projects

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:

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 (see Appendix II, Table IId)

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 7 Estimated CO_2 Baseline Emissions for New Capacity Projects

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

Where:

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

F_i = estimated fuel consumption for project, MMBtu

Clean Development Mechanism (CDM)

The baseline emissions calculation approach taken by the CDM methodology - AM0044[58] - presented in Section 1 is the following:

Step 1 – Determine the thermal efficiency of each baseline boiler

Equation 8 Baseline Thermal Efficiency

$$\eta_{BL,m,i} = \frac{EG_{BL,his,i}}{FC_{BL,his,i}}$$

Where:

$\eta_{BL,m,,i}$ = Average baseline thermal efficiency of boiler 'i'.
$EG_{BL,his,i}$ = Average historic thermal energy output from the baseline boiler 'i' (MJ/yr).
$FC_{BL,his,i}$ = Average historic fossil fuel consumption from the baseline boiler 'i' (MJ/yr).

To address the potential issue of lack of historic data to make this determination, the methodology allows for measurements to be taken to estimate current efficiency. These measurements have to be assigned an uncertainty level by an independent expert. Depending on what this expert finds, the uncertainty can be grouped into 5 tiers as noted in the table below. Depending on the tier assigned, a multiplication (conservativeness) factor is applied to baseline emission estimates.

Table 21 Baseline Emissions Conservativeness Factor

Estimated uncertainty range (%)	Assigned uncertainty band (%)	Conservativeness factor where higher values are more conservative
Less than or equal to 10	7	1.02
Greater than 10 and less than or equal to 30	20	1.06
Greater than 30 and less than or equal to 50	40	1.12
Greater than 50 and less than or equal to 100	75	1.21
Greater than 100	150	1.37

[58] http://cdm.unfccc.int/UserManagement/FileStorage/CDMWF_AM_L4AQZSBA770KNI0BUSG1JVIWCXIFU5

Step 2 – Calculate fossil fuel input for each baseline boiler (MJ/yr) that would have been needed in the absence of the project activity

The methodology provides the following equation:

Equation 9 Fossil Fuel Input per Baseline Boiler

$$FC_{BLe,i,y} = \left(\frac{EG_{PJ,i,y}}{\eta_{BL,i}} \right) * CF_{i,y}$$

Where:

$FC_{BLe,i,y}$ = Calculated input of fossil fuel to baseline boiler 'i' in year 'y' (MJ/yr)
$EG_{PJ,i,y}$ = Thermal energy output of project boiler 'i' in year 'y' (MJ/yr)
$CF_{i,y}$ = Activity capping factor for boiler 'i' in year 'y'.

Step 3 – Calculate baseline emissions from combustion of fossil fuel in each baseline boiler (tCO2/yr)
Baseline emissions from the combustion of fossil fuel for each boiler in the baseline is determined using the below formula:

Equation 10 Baseline Emissions per Baseline Boiler

$$BE_{i,y} = FC_{BL,i,y} \cdot EF_{C,FF,i} \cdot OXID_{FF,i} \cdot 44/12 \quad \textbf{(4)}$$

Where:

$BE_{i,y}$ = Baseline emissions for fossil fuel combustion at boiler 'i' in year 'y' (tCO_2/yr)
$FC_{BL,i,y}$ = Input of fossil fuel to baseline boiler 'i' in year 'y'(MJ/yr)
$EF_{C,FF,i}$ = Emission factor for the fossil fuel used in the boiler 'i' (tC/MJ).
$OXID_{FF,i}$ = Oxidation factor for the fossil fuel used in the boiler 'i' (fraction).
44/12 = Conversion factor: carbon equivalent to CO_2 eq (ratio: molecular weight of CO_2 / molecular weight of carbon)

There are two significant differences in the calculation procedures. The EPA Climate Leaders provides a number of look up tables and references that detail the emission factors for CO_2, CH_4, and N_20 in order to reduce the burden on the project developer and ensure greater consistency in emission calculations. The CDM approach provides a default methodology for determining boiler efficiencies where historic data is lacking. In the US, this appears to be largely unnecessary, as boiler efficiency data from manufacturers exists in all but a few old boilers.

6 Potential Reduction Opportunity

6.1 Technical Potential

The estimate of the market potential requires a significant amount of information on the existing installed boiler characteristics as well as data on the new boilers being installed. The analysis provided below represents an estimate of the total technical potential for fuel savings of boilers based on some broad assumptions. These results are provided to illustrate the relative impact of the potential savings by boiler segment. The potential emissions reduction based on an estimate of the technical potential in the US market is summarized as follows:

- Industrial Boilers: 56,060,147 tCO_2e/year
- Commercial Boilers: 22,673,929 tCO_2e /year
- Residential Boilers: 6,584,231 tCO_2e /year

The details on the methodology, data sets and assumptions to arrive at these estimates are presented below.

Industrial Boilers Market

The following tables are from a May 2005 study, *Characterization of the U.S. Industrial Commercial Boiler Population*, by Oak Ridge National Laboratory (ORNL) and present the industrial boiler population in the United States.[59] The following table presents the total installed capacity for the industrial boiler population.

Table 22 Industrial Boiler Inventory in the United States - Number of Units - 2005

	Food	Paper	Chemicals	Refining	Metals	Other Manufacturing	Total
< 10 MMBtu/hr	6,570	820	6,720	260	1,850	7,275	23,495
10-50 MMBtu/hr	3,070	1,080	3,370	260	920	3,680	12,380
50-100 MMBtu/hr	570	530	950	260	330	930	3,570
100-250 MMBtu/hr	330	540	590	200	110	440	2,210
>250 MMBtu/hr	70	490	350	220	120	110	1,360
Total	10,610	3,460	11,980	1,200	3,330	12,435	43,015

Table 23 Industrial Boiler Inventory in the United States - Total Capacity - 2005

	Food	Paper	Chemicals	Refining	Metals	Other Manufacturing	Total
< 10 MMBtu/hr	31,070	4,105	28,660	1,255	7,505	29,710	102,305
10-50 MMBtu/hr	64,970	24,490	81,690	6,670	19,405	80,585	277,810
50-100 MMBtu/hr	37,885	36,665	64,970	18,390	22,585	62,630	243,125
100-250 MMBtu/hr	47,950	81,500	8,640	30,480	17,775	62,790	249,135
>250 MMBtu/hr	27,860	229,590	150,915	114,720	45,365	47,760	616,210
Total	209,735	376,350	334,875	171,515	112,635	283,475	1,488,585

[59] *Characterization of the U.S. Industrial Commercial Boiler Population*, Oak Ridge National Laboratory, May 2005

The data shows that there are a total of 43,000 industrial boilers with a combined installed capacity of 1,488,585 MMBTU/hour. Historic sales trends for larger water-tube boilers (>100 and >250 MMBtu/Hour) have dropped dramatically after the 1974 energy crisis and economic recession. Sales dropped from hundreds per year to dozens per year and have not recovered except for a brief increase during 1999 to 2002. These sales were primarily for natural gas and waste heat recovery boilers, possibly related to the gas power plant construction boom during this period.

Given the low level of sales over the last 30 years, the existing installed inventory is now quite old. The sales data for units larger than 10 MMBtu/Hour indicates that 47 % of boiler capacity is at least 40 years old and 76 % is at least 30 years old. Of the 1,350 very large boilers (>250 MMBtu/Hour) about 900 are more than 30 years old.

This data indicates that the highest impact associated with a performance threshold is likely to have the most impact associated with retrofits of existing boilers. Since a threshold has not yet been defined, an estimate of the market impact requires many assumptions. An estimate has been made and is presented in the following table. Major assumptions include the percent of existing boilers that can be retrofit, the percent of boilers that are stand alone and in lead/lag configurations. The standalone boilers are assumed to be down for scheduled maintenance for two week per year. The lead boiler is assumed to operate 8,760 hours per year and the lag boilers are assumed to operate 40% of the time. The corresponding boiler loading has been estimated as well. For the purposes of this estimate, the savings are based on an average efficiency of the installed base of boilers at 75% and that the threshold would be at 86%. The total annual savings presented at the bottom of the table is the estimated technical potential (i.e. the value if all the eligible boilers were to be upgraded). An annual projection would require an assumption for the economics of the boiler upgrade and then the market penetration would be estimated through an adoption model.

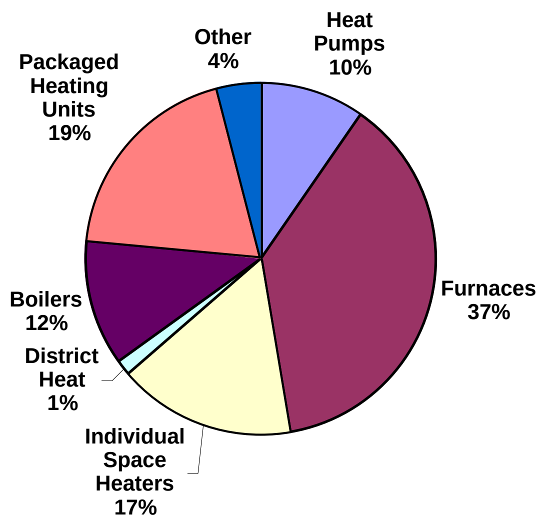
Table 24 Technical Potential – Industrial Boilers

Existing Boiler Characteristics	
Total number of Existing Boilers	43,015
Installed Capcacity (MMBTU/hr)	1,488,585
Average Capcity/Boiler (MMBTU/hr)	34.6
Precent of Boilers Eligible for Retrofit	80%
Percent of Boilers in Lead/Lag Configuration	80%
Estimated Number of Eligible Stand Alone Boilers	6,882
Estimated Number of Lead Boilers	13,765
Estimated Number of Lag Boilers	13,765
Estimated Annual Hours of Operation	
Stand Alone	8424
Lead	8760
Lag	3504
Typical Loading	
Stand Alone	80%
Lead	90%
Lag	50%
Average Exsiting Boiler Efficiency	75%
Annual Fuel Consumption for All Boilers	
Stand Alone (MMBTU/year)	2,140,132,700
Lead (MM BTU/year)	5,007,361,766
Lag (MMBTU/year)	1,112,747,059
Total Fuel Consumption (MMBTU/year)	8,260,241,526
Estimated Retrofit Threshold	86%
Annual Fuel Consumption for All Boilers @ Threshold	
Stand Alone (MMBTU/year)	1,866,394,797
Lead (MM BTU/year)	4,366,885,261
Lag (MMBTU/year)	970,418,947
Total Fuel Consumption (MMBTU/year)	7,203,699,005
Annual Savings Technical Potential	
Stand Alone (MMBTU/year)	273,737,904
Lead (MM BTU/year)	640,476,505
Lag (MMBTU/year)	142,328,112
Total Fuel Savings (MMBTU/year)	***1,056,542,521***
Total CO_2 Emissions (tCO_2/year)	56,060,146
Total CH_4 Emissions (tCO_2e/year)	1.057
Total N_2O Emissions (tCO_2e/year)	0.106
Total Emissions Reduction (tCO_2e/year)	***56,060,147***

Commercial Boilers Market

The following figure shows the mix of heating systems in commercial buildings as reported by the Energy Information Administration, Office of Energy Markets and End Use, Form EIA-871A of the 2003 Commercial Buildings Energy Consumption Survey. Commercial boilers represent 12% of the installed base.

Figure 5 Commercial Building Heating Equipment



The following table presents the installed based of commercial boilers[60].

Table 25 Installed Commercial Boilers

Building Type	Number of Boilers	Boiler Capacity (MMBtu/hr)	Average Size (MMBtu/hr)
Office	28,030	297,090	10.6
Warehouse	5,365	72,385	13.5
Retail	5,585	47,230	8.5
Education	35,895	128,790	3.6
Public Assembly	7,280	55,205	7.6
Lodging	10,545	140,830	13.4
Health	15,190	317,110	20.9
Other	11,900	88,970	7.5
Total	**119,790**	**1,147,610**	**9.6**

[60] *Characterization of the U.S. Industrial Commercial Boiler Population*, Oak Ridge National Laboratory, May 2005

Note that electric boilers are not included in the data presented in the preceding table.

Since a threshold has not yet been defined, an estimate of the market impact requires many assumptions. An estimate has been made and is presented in the following table. Major assumptions include the percent of existing boilers that can be retrofit, the percent of boilers that are stand alone and in lead/lag configurations. The standalone boilers are assumed to be down for three months during the summer season. The lead boilers are assumed to operate the same number of hours as the standalone boilers and the lag boilers are assumed to operate 40% of the lead boiler hours of operation. The corresponding boiler loading has been estimated as well. For the purposes of this estimate, the savings are based on an average efficiency of the installed base of boilers at 77% and the threshold is estimated to be 83%. The total annual savings presented at the bottom of the table is the estimated technical potential (i.e. the value if all the eligible boilers were to be upgraded). An annual projection would require an assumption for the economics of the boiler upgrades and then the market penetration would be estimated through a Bass model.

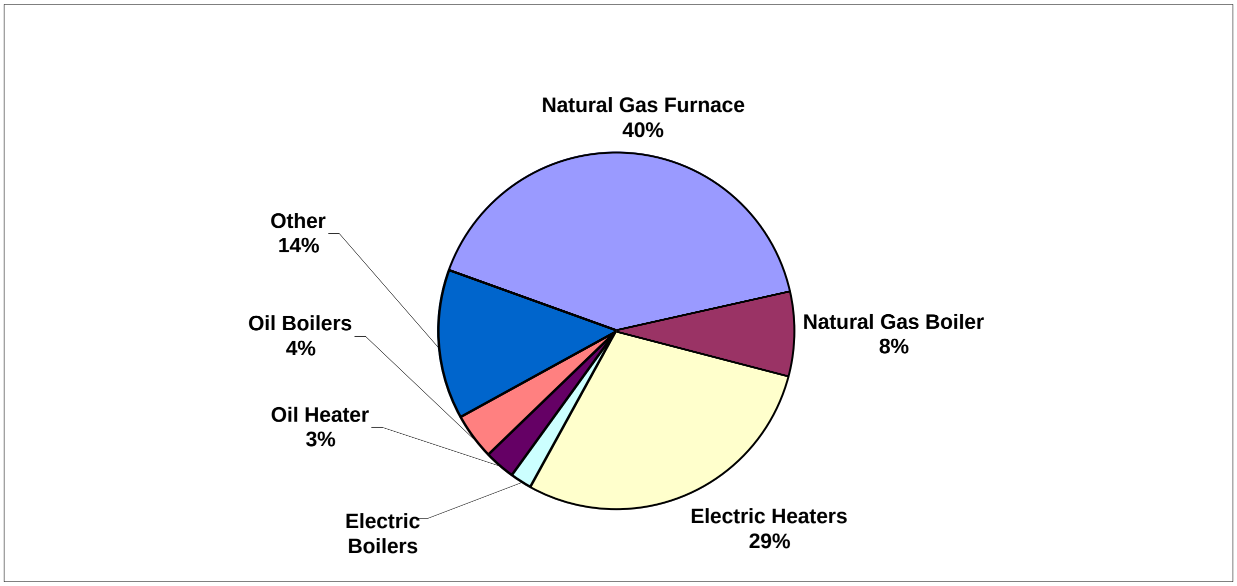
Table 26 Technical Potential – Commercial Boilers

Existing Boiler Characteristics	
Total number of Existing Boilers	119,790
Installed Capcacity (MMBTU/hr)	1,147,610
Average Capacity/Boiler (MMBTU/hr)	9.6
Precent of Boilers Eligible for Retrofit	75%
Percent of Boilers in Lead/Lag Configuration	90%
Estimated Number of Eligible Stand Alone Boilers	8,984
Estimated Number of Lead Boilers	40,429
Estimated Number of Lag Boilers	40,429
Estimated Annual Hours of Operation	
Stand Alone	6570
Lead	6570
Lag	2628
Typical Loading	
Stand Alone	70%
Lead	90%
Lag	50%
Average Exsiting Boiler Efficiency	77%
Annual Fuel Consumption for All Boilers	
Stand Alone (MMBTU/year)	514,077,116
Lead (MM BTU/year)	2,974,303,313
Lag (MMBTU/year)	660,956,292
Total Fuel Consumption (MMBTU/year)	4,149,336,721
Estimated Retrofit Threshold	85%
Annual Fuel Consumption for All Boilers @ Threshold	
Stand Alone (MMBTU/year)	465,693,387
Lead (MM BTU/year)	2,694,368,884
Lag (MMBTU/year)	598,748,641
Total Fuel Consumption (MMBTU/year)	3,758,810,912
Annual Savings Technical Potential	
Stand Alone (MMBTU/year)	48,383,729
Lead (MM BTU/year)	279,934,430
Lag (MMBTU/year)	62,207,651
Total Fuel Savings (MMBTU/year)	***390,525,809***
Total CO_2 Emissions (tCO_2/year)	20,721,299
Total CH_4 Emissions (tCO_2e/year)	1,952,629
Total N_2O Emissions (tCO_2e/year)	0.039
Total Emissions Reduction (tCO_2e/year)	***22,673,929***

Residential Boilers Market

The following figure shows the mix of heating systems in residential applications as reported by the Energy Information Administration, Office of Energy Markets and End Use, 2005 Residential Energy Consumption Survey. Residential boilers represent 12% of the installed base.

Figure 6 Residential Heating Equipment



The data shows that boilers represent 14.8% of the installed residential heating base with the following breakouts by boiler fuel type:

- Natural Gas Boilers: 8,200,000 units
- Oil Fuel Boilers: 4,700,000 units
- Electric Boilers: 1,900,000 units

Since a threshold has not yet been defined, an estimate of the market impact requires many assumptions. An estimate has been made and is presented in the following table. Major assumptions include the percent of existing boilers that can be retrofit, the average capacity of the installed boiler population, and the annual hours of operation. For residential boilers, the hours of operation are based on the outside are temperature and the thermostat setting. As such, the estimate of the annual hours of operation on a national scale is very rough and subject to more analysis or data gathering. The average boiler size is estimated to be 60,000 BTU/hour. For the purposes of this estimate, the savings are based on an average efficiency of the installed base of boilers at 77% and the threshold is estimated to be 83%. The total annual savings presented at the bottom of the table is the estimated technical potential (i.e. the value if all the eligible boilers were to be upgraded). An annual projection would require an assumption for the economics of the boiler upgrades and then the market penetration would be estimated through a Bass model.

Table 27 Technical Potential – Residential Boilers

Existing Boiler Characteristics	
Total Number of Existing Boilers	12,900,000
Average Capacity/Boiler (MMBTU/hr)	0.06
Precent of Boilers Eligible for Retrofit	80%
Estimated Number of Eligible Boilers	10,320,000
Estimated Annual Hours of Operation	
All Boilers	2738
Typical Loading	
All Boilers	50%
Average Exsiting Boiler Efficiency	77%
Annual Fuel Consumption for All Boilers	
All Boilers (MMBTU/year)	1,100,688,312
Estimated Retrofit Threshold	85%
Annual Fuel Consumption for All Boilers @ Threshold	
All Boilers (MMBTU/year)	997,094,118
Annual Savings Technical Potential	
All Boilers (MMBTU/year)	***103,594,194***
Total CO_2 Emissions (tCO_2/year)	6,254,977
Total CH_4 Emissions (tCO_2e/year)	329,253
Total N_2O Emissions (tCO_2e/year)	0.029
Total Emissions Reduction (tCO_2e/year)	***6,584,231***

7 Ownership

Ownership issues for boilers are fairly clear cut, with a possible exception for smaller commercial and residential boilers. Although the home owner or business owner will typically own the boiler, utilities or the local government could in the future choose to enter in to programmatic agreements for offsets which could in turn create different forms of ownership or leasing of offsets and equipment. To date, utilities have approached these programmatic efforts by assisting the project in a variety of ways up to and including joint venture partnerships. The utilities have also been very interested in ownership of the emission reduction right and it is transferred to the utility in an offset sales agreement. However, in the future, more complex arrangements are possible including joint venture ownership of the emission offsets. The future could also see the rise of commercial offset consolidators who enter into agreements with businesses and residents to help improve their boiler efficiencies and concurrently buy up the emission rights. It should be noted that this is different from how energy efficiency reductions are treated, since EE reductions have not been designed to be a traded commodity as GHG offsets have been. EE improvements are tracked (but not traded) to comply with State EE regulations such as California's AB 2021 which mandates utilities improve their EE performance through 2017 by 10%.

8 Project Boundary and Leakage

In most cases, the physical project boundary should be limited to the boiler unit, including the technology options installed to improve boiler performance. This would include the boiler exhaust, the incoming combustion air, and the heat recovery system. However, project developers must make upstream and/or downstream adjustments to the physical boundary in the following special cases:

- Projects where the new boiler results in changes to the efficiency of the current steam distribution system;
- Projects where the steam system affects fuel use in the new boiler;
- Projects where the electricity use associated with the boiler auxiliaries (e.g., the burner assembly or exhaust gas recirculation) changes as a result of the new boiler. In this case, the emissions from electricity should be included in the physical boundary, either as direct emissions or indirect emissions, if generated off-site; and
- Any changes in methane (CH_4) leakage from the natural gas distribution system, for example, from a switch from fuel oil to natural gas in the boiler.

If the performance standard addresses fuel oil or biomass fuel, the boundary may be expanded to take into account the processes associated with the delivery of the fuel. Both fuel types are likely to be delivered in a batch process by truck or rail on a regular basis. Emissions from the transportation vehicle can be attributed to the fuel selection of the boiler. For biomass boilers, a by-product of the process is ash that must be removed from the system and disposed. If the ash removal is by means of truck or rail, the emissions associated with this disposal could also be included in the emission associated with the boiler.

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 project boundary that fully or partially negate the benefits of the project.

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. Thus, this leakage is not an issue for new capacity projects or for replacements of boilers that are permanently retired. 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 CO2 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. Leakage can also be attributed to the processing and transportation of fuel oil and biomass fuels as discussed in the Project Boundary section above. A significant potential for biomass boiler leakage issues exists due to potential land use changes to produce the biomass. Recent studies conducted by the State of California on biofuels[61] indicate that the life cycle GHG emissions from land use conversions to grow certain energy crops can be almost as high as fossil fuels. The following table shows some of these relationships.

Table 28 Full Cycle Comparison of GHG Emissions

Emissions - Fuels and Pathways

Fuel	Pathway	Carbon Intensity (gCO2e/MJ)
California Gasoline	CARBOB	92
Low Sulfur Diesel	Conventional Crude Oil	88
Fischer-Tropsch Diesel	Coal	167
LPG	Conventional Petroleum	77
CNG	North America Nat Gas	79
Electricity	CA Average Mix	27
Biodiesel	Midwest Soybeans	31
Ethanol	Midwest Corn	113
Ethanol	CA Corn	52
Ethanol	Cellulose	7
Ethanol	Sugar Cane	40
Hydrogen	Reformed Natural Gas	48
Source: California Energy Commission, "Well to Wheels" Full Fuel Cycle Analysis Report, June 2007.		

On the other hand, some pelletized wood suppliers for biomass boilers are using wood by-products such as bark and chips. Since these by-products may be headed for waste, the GHG life cycle emissions in using these in biomass boilers would be very good. To move forward biomass boilers as an offset opportunity, considerable research would have to be done on fuel types, land use issues, etc.

[61] *Full Fuel Cycle Assessment: Well to Wheels Energy Inputs, Emissions and Water Impacts: State Plan to Increase the Use of Non-Petroleum Transportation Fuels* - AB 1007 (Pavley) *Alternative Transportation Fuels Plan Proceeding*, REVISED Final Consultant Report #CEC-600-2007-004-REV. Original posted June 22, 2007; revised posted August 1, 2007.

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.

9 Permanence

This concept is usually applied to project with an inherent risk of catastrophic failure and reversal such as carbon sequestered in forests and through wetland restorations. The duration and permanence of boiler projects would appear to pose very low risk.

10 Scientific Uncertainty

Uncertainty for boiler efficiency projects is fairly low and revolves around monitoring techniques that are well established and reliable. Four monitoring options are available for monitoring of emissions from boilers: (1) direct measurement of input fuel and heat output, (2) direct fuel volume measurement; (3) steam or hot water measurement; and (4) direct stack CO2 measurement.

10.1 Direct Efficiency Measurement

The most accurate and most costly approach to verify the operation of a boiler is measure the fuel input and the heat output. The fuel input can be measured with a commercially available natural gas meter. The meter must be placed at the boiler and if the point of fuel connection is far from the utility natural gas meter and pressure regulator, the boiler gas meter should have pressure and temperature compensation. The output energy can be in the form of steam or hot water. Steam can be measured with a steam flow meter. The determination of the heating value of the steam requires the steam temperature and pressure to also be monitored. Hot water can be measured with a liquid flow meter, the supply temperature and the return temperature. Note that for multiple boiler systems, this monitoring approach needs to be applied to each boiler.

The typical accuracy of the devices is as follows:

- Pressure and Temperature Compensated Natural Gas Meter: +/- 1.0%
- Steam Meter, Pressure sensor and Temperature Sensor: +/- 2 - 5%
- Hot Water BTU Meter (flow, supply and return temperature): +/- 2.5%

Areas of error can occur in the following areas:

- Assumptions of the heating value for the natural gas. (if the same value is used for the baseline and the installed unit then the comparative error cancels even though the actual value could be off)
- Steam flow meters are not accurate at low flow (generally 30% of the design flow rate) so if the steam flow is variable, an error in the measurement could be introduced.

- Liquid flow meters must be placed in a long length of straight pipe so that liquid turbulence does impact the measurement.
- Temperature sensors should be installed in thermowells so that the probe is in the fluid flow and conductive grease should be used to ensure a transfer of heat from the well to the temperature probe.
- For the highest level of accuracy an automated data collection system should be used to reduce human error in sensor reading, data value recording and interval timing.

10.2 Direct Fuel Measurement

The direct fuel measurement approach is the same as the input fuel measurement methodology described above. Since the GHG emissions are generated from the combustion of the fuel, a calculation of the GHG impact due to the fuel consumed can be made. Lacking any additional information on the process, one cannot determine if less fuel consumption is attributed to the higher efficiency boiler or a reduction in boiler load.

10.3 Boiler Output Measurement (Steam or Hot Water)

The boiler output measurement approach is the same as the steam and hot water measurement methodology described above. Using this approach, one must assume that the manufacturer efficiency rating is correct and that it does not vary with boiler load. Once the output is determined and the boiler efficiency is assumed, one can calculate the quantity of fuel that was consumed. Using this approach, one can evaluate if the loading of the boiler has changed from one period to the next and see the resulting change in fuel consumption.

10.4 Direct Stack CO2 Measurement and Continuous Emissions Monitors (CEMS)

The direct stack CO2 measurement or CEM methodology uses a set of three instruments to directly measure the CO2 emissions from the boiler stack. A gas analyzer is used to measure the concentration of CO2, a flow meter is used to measure the flow rate of the flue gases in the boiler stack, and a temperature sensor is used to measure the temperature of the exhaust gas. A data integrator is used to integrate the CO2 concentration and the flue gas flow rate over a given time period. Exhaust gas measurements are difficult and require equipment that is calibrated on a regular basis against a known source gas. Due to the high temperatures of the exhaust, one must take care in selecting a flow meter for this application. This approach is best suited for periodic annual testing by a certified emissions testing company. If the annual test takes measurements at defined boiler output levels and the boiler output levels are also recorded through the year, a correlation of CO2 emissions to boiler loading and hours of operation at each loading level can be used to determine the annual level of CO2 emissions.

11 Other Positive/Negative Environmental, Public Health and Social/Economic Impacts

This section summarizes some other possible impacts of the fuels and technologies considered for this methodology. From a broader perspective, boiler efficiency incentive programs should reduce overall emissions of criteria pollutants along with GHG emission reductions, resulting in cleaner air for the general population. However, in confined air basins the possible effects from switching electric boilers to natural gas should be considered, since local utility generation emissions in remote locations could be transferred into the commercial and residential matrix of the population. Still, modern residential and commercial boilers have low NOx emission options and the overall benefit should be significant when considering the improved efficiencies versus power plant generation. In the case of biomass, incentivizing higher particulate emissions in urban areas may not be appropriate.

In the case of a residence or commercial enterprise that installs sufficient Solar PV to become grid neutral, a boiler methodology could provide additional incentives – assuming that an electric boiler was installed and ran off of the installed PV. Any shift to increased renewables and reduced fossil fuel reliance is believed by many to improve national energy security.

12 Market Interest

Informal surveys conducted for this study indicate a strong interest in boiler efficiency projects from larger end users (commercial and industrial). These projects have dual benefits of fuel savings along with GHG potential offset incentives. There is less interest from smaller commercial establishments and residences, but some utilities are interested in programmatic offset efforts to incentivize these customers of theirs.

There is generally less interest from industrial boiler users who are facing the reality of an emissions cap in 2012 sine there is felt to be insufficient time to install the project and get offsets. The 2015 time frame poses less of a problem, since this would allow for up to 6 years of offset rewards before any mandatory cap is effective.