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AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers

Prepared by the

Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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I. Introduction

This document is one of several white papers that summarize readily available information on control techniques and measures to mitigate greenhouse gas (GHG) emissions from specific industrial sectors. These white papers are solely intended to provide basic information on GHG control technologies and reduction measures in order to assist States and local air pollution control agencies, tribal authorities, and regulated entities in implementing technologies or measures to reduce GHGs under the Clean Air Act, particularly in permitting under the prevention of significant deterioration (PSD) program and the assessment of best available control technology (BACT). These white papers do not set policy, standards or otherwise establish any binding requirements; such requirements are contained in the applicable EPA regulations and approved state implementation plans.

II. Purpose of This Document

This document provides information on control techniques and measures that are available to mitigate greenhouse gas (GHG) emissions from industrial, commercial, and institutional (ICI) boilers at this time. While a large number of available technologies are discussed here, this paper does not necessarily represent all potentially available technologies or measures that that may be considered for any given source for the purposes of reducing its GHG emissions. For example, controls that are applied to other industrial source categories with exhaust streams similar to the cement manufacturing sector may be available through "technology transfer" or new technologies may be developed for use in this sector.

The information presented in this document does not represent U.S. EPA endorsement of any particular control strategy. As such, it should not be construed as EPA approval of a particular control technology or measure, or of the emissions reductions that could be achieved by a particular unit or source under review.

III. Description of ICI Boilers

Industrial boilers encompass the category of boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. Industrial boiler systems are used for heating with hot water or steam in industrial process applications. Industrial boilers are located at facilities in the food, paper, chemicals, refining, and primary metals industries. There is no precise regulatory definition or specific size requirement for an industrial boiler. An industrial boiler is typically defined by its common function – a boiler that provides heat in the form of hot water or steam for co-located industrial process applications. This industrial boiler category does not include electric utility boilers as these do not provide the same service. An electric utility boiler is defined as a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.

Commercial boilers encompass the category of boilers used in commercial establishments such as hotels/motels, restaurants, stores, office buildings, apartment buildings, and laundries to provide steam and/or hot water. Commercial boiler systems are used for heating with hot water or steam in commercial buildings. Commercial boilers are generally small in size compared to industrial boilers. A commercial boiler is typically defined by its common function – a boiler that provides heat or hot water for a commercial building or facility.

Institutional boilers encompass the category of boilers used in institutional establishments such as medical centers, universities, schools, government buildings, and military installations to provide steam, hot water, and/or electricity. Institutional boiler systems are used for heating with hot water or steam. A majority of these are located at educational facilities.

ICI boilers can use a number of different fuels including coal (bituminous, sub bituminous, anthracite, lignite), fuel oil, natural gas, biomass (wood residue, bagasse), liquefied petroleum gas, and a variety of process gases and waste materials. Each of these fuels has different combustion characteristics and produces distinct GHG emissions. Coal is the highest CO_2 producer in ICI boilers with an average emission factor of 93.98 kg CO_2/million British thermal units (MMBtu); natural gas has the lowest emissions of CO_2 from ICI boilers with an average emission factor of 53.06 kg CO_2/MMBtu. (EPA, 2008)

Figure 1 presents a process flow diagram of a typical industrial boiler system. Combustion for heat generation begins in the boiler burner system and the heat is transferred to the water in the boiler. The boiler produces steam and hot water for industrial process applications. Many boilers use an economizer to preheat the process water before it is fed to the boiler using waste heat from the exhaust gas. This combustion operation produces CO_2 emissions and is the focus of the emission reduction techniques presented in the remainder of this document.

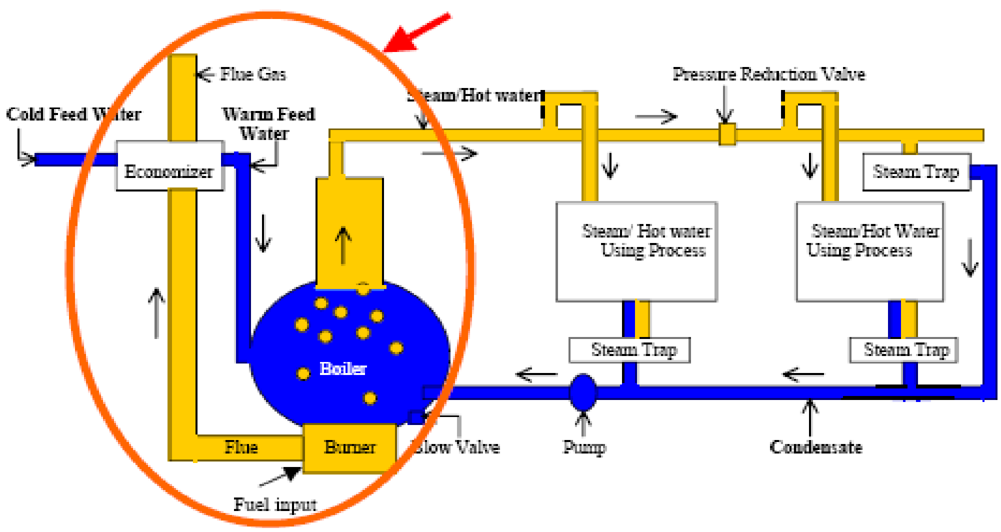


Figure 1. Schematic of an Industrial Boiler System.
Source: EPA, 2008

IV. Description of ICI Boiler Design Types

This section includes a brief description of the ICI boiler designs. The most common ICI boiler designs are:

1. Pulverized coal,
2. Fluidized bed,
3. Stoker,
4. Watertube, and
5. Firetube.

Each design has unique characteristics and can be used in various applications and industries. Some of these designs use multiple fuels. The larger of these boiler designs can be used to produce electricity, steam, or both.

1. *Pulverized Coal*

Pulverized-coal (PC) boilers offer a more efficient alternative to stokers for burning coal. PC boilers are used in large ICI units. In PC boilers, the coal is pulverized to very small particles in large devices called pulverizers or mills. These coal particles are then blown with air into the boiler through a "burner," where they are then burned in suspension in the furnace. PC boilers are usually characterized by the burner configuration (tangential, wall, cyclone) and whether the bottom ash exits the boiler in solid or molten form (dry bottom vs. wet bottom) (EEA, 2005).

2. *Fluidized Bed*

Fluidized-bed combustors (FBC) are boilers of a more recent design and were developed for solid fuel combustion. In FBC, combustion takes place in suspension as in a PC boiler, but instead of individual burners controlling the air/fuel mixing, fuel and a mixture of inert material (e.g., sand, silica, ash, sorbent products) are kept suspended above the bed by an upward flow of combustion air through the fuel bed. This fluidization improves mixing of fuel and air, as well as allowing for higher residence times in the furnace (the retention time of the fuel in the bed). FBC are inherently suited for various fuels, including low-grade fuels such as petroleum coke, coal refuse, municipal waste, and biomass materials.

Even though FBC boilers do not constitute a large percentage of the total ICI boiler population, they have gained popularity in the last few years, due primarily to their capabilities to burn a wide range of solid fuels and their low- nitrogen oxide (NO_X)/sulfur dioxide (SO_2) emission characteristics.

There are two major types of FBC systems currently in operation in the ICI sector: (1) bubbling bed – operating at a fluidizing velocity that is less than the terminal velocity of individual bed particles, and (2) circulating bed – operating at fluidizing velocity that exceed the terminal velocity of individual bed particles.

3. ***Stoker***

Stoker boilers have been around the longest. In stoker boilers, the fuel is combusted in relatively thin layers on top of a "grate." Stoker boilers are typically characterized according to the way fuel is transported to the grate. There are several ways to accomplish this. The most common type is the spreader stoker, where the fuel is "spread" above the grate, allowing the fines to combust in suspension while the heavier pieces fall to the grate and combust. Another type, underfeed stokers, essentially "push" the fuel into the bottom of the fuel bed, where it is volatized and combusted by the time it reaches the top of the bed. Chain-grate, traveling-grate, and water-cooled vibrating-grate stokers are less common configurations, but all achieve the goal of maintaining a thin bed of burning fuel on the grate.

As with PC boilers, heat is transferred from the fire and combustion gases to watertubes on the walls of the boiler. Stokers can burn a variety of solid fuels, including coal and various wood and waste fuels.

4. ***Watertube***

Large Watertube.

As the name suggests, the large watertube boiler category is classified by its size. The sizes range generally from 10 to 10,000 million Btu per hour (MMBtu/hr). Large watertube boilers account for the majority of steam production and use mostly solid fuels. They comprise the boiler technologies described above, which include PC, FBC, and stoker boilers. Higher-capacity watertube ICI boilers often use a combustion air preheat to improve overall efficiency.

In watertube boilers, the fuel is combusted in a central chamber (furnace, bed, or grate) and the combustion gas transfers heat energy, through radiation and convection, to the water circulating in the metal tubes. The number of tubes varies greatly depending on boiler capacity. The watertubes are often welded together to form the walls of the combustion chamber in a so-called "waterwall." Water circulates through the pipes, and the flow is designed to take advantage of different thermal zones to achieve specific steam conditions. Watertube boilers can produce steam at very high temperatures and pressures, but these boilers tend to be more complex and expensive than firetube units.

Small Watertube.

In terms of the ICI boiler population, most watertube boilers are sized under 10 MMBtu/hr and, hence, characterized as small. These small watertubes are mostly oil- and gas-fired boilers. Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat and hot water for industrial, commercial, and institutional facilities. Fundamentally, these boilers operate within the same principles as their "large" counterparts.

5. ***Firetube***

Firetube units are typically the smallest boilers, with most units less than 10 MMBtu/hr in capacity. Almost all firetube boilers burn oil, gas, or both. In a firetube boiler, the “fire” and the water trade places. The water is stored in the main body of the boiler, while the combustion gases flow through one or several metal tubes within the body of the boiler. Heat is transferred to the water by conduction from the firetube(s) to the surrounding water. Firetube boilers are characterized by the number of “passes” the firetubes make through the boiler water. Increasing the number of passes increases overall efficiency. The advantages of firetube boilers are their simplicity and low cost. The mixing of the water in one large chamber makes a firetube boiler well suited to producing hot water or low-pressure steam. Firetube boilers are typically pre-fabricated and shipped to the site.

V. Summary of Measures to Reduce GHGs

Table 1 summarizes the GHG emission reduction measures for existing ICI boilers presented in this document. Where available, the table includes emission reduction potential, energy savings, costs, and feasibility of each measure. Generally, efficiency gains are a function of the difference between the new and old technologies or processes and are expressed in percent.

Table 1. ICI Boilers – Summary of Greenhouse Gas Emission Reduction Measures

GHG Measure	Applicability	Efficiency Improvement (percentage pt)	CO_2 Reduction (%)	Capital Costs	Notes/Issues
Energy Efficiency Improvements					
Replace/ Upgrade Burners	All, except for Stoker-type boilers and fluidized bed boilers	Up to 4-5%.	Up to ~ 6%.	$2,500 – 5,100 per MMBtu/hr	Site specific considerations (retrofit ability) and economic factors may affect the installation of burners
Tuning	All	CO from 1000-2000 to < 200 ppm Unburned carbon (UBC) from 20-30% to 10-15%	up to ~3%	Up to $3000	Manual tuning with parametric testing
Optimization	All	0.5% – 3.0%	up to ~ 4%	$100,000	Neural network-based
Instrumentation & Controls	All, especially at large plants	0.5% – 3.0% (in addition to optimization)	up to ~ 4%	>$1million	System integration, calibration, and maintenance
Economizer	Units with capacity over	40°F decrease in flue gas temperature	Relates to efficiency	$2.3 million	Larger units; must consider pressure

	25,000 pounds of steam per hour;	equals 1% improvement	gain in boiler	(for 650 MMBtu/hr)	loss, steam conditions
Air Preheater	Units with capacity over 25,000 pounds of steam per hour;	A 300°F decrease in gas temperature represents about 6% improvement	~ 1% per 40°F temperature decrease	$200,000 – 250,000 (for 10MMBtu/hr)	Used in large boiler applications, not widely used in ICIs due to increase in NO_X
Create turbulent flow within firetubes	Single or two pass firetube boilers	1% efficiency gain for 40°F reduction in flue gas temperature 100°F -150°F temperature decrease potential	~ 1% per 40°F temperature decrease up to ~ 4%	$10 – 15 per tube	Widely accepted with older boilers;
Insulation	All, most suitable for surface temperatures above 120°F	Dependent on surface temperature	Up to 7%		Radiation losses increase with decreasing load
Reduce air leakages	All	1.5 – 3% potential (Effect similar to reducing excess air)	Up to ~ 4%	Site-specific (None to cost of maintenance program)	Requires routine maintenance procedures
Capture energy from boiler blowdown	Most suitable for units w/ continuous boiler blowdown exceeding 5% of steam rate	Site specific depending on steam conditions Up to ~ 7%	Up to ~ 8% See efficiency comment	NA	Water quality issue important
Condensate return system	All; However, larger units more economical to retrofit	Site specific - depends on condensate temperature and % recovery	Same as efficiency improvement, ratio of Btu/hr saved from condensate to Btu/hr input	$75,000	Energy savings is the energy contained in the return condensate, condensate quality affects use
Reduce slagging and fouling of heat transfer surfaces	Watertube boilers	1% to 3% Site specific; fuel quality/operating condition have large impact	Up to ~ 4%	$50,000 to $125,000	Downtime/economic factors, regain lost capacity
Insulating jackets	Surfaces over 120°F		Same as efficiency improvement	Depends on length/type of insulation required for implementation	No deployment barriers

Reduce steam trap leaks	All			None to cost of maintenance program	No deployment barriers
Post-Combustion					
Carbon capture and storage					demonstrated at the slip-stream or pilot-scale
Other Measures					
Alternative fuels – biomass	All fossil fuels				Less caloric content than fossil fuel
Co-firing	Coal-fired and oil-fired boilers	reduction up to 2% for biomass co-firing	20-30% reduction with gas co-firing		Negative impact of boiler efficiency
Fuel switching	Coal-fired and oil-fired boilers		20-35% reduction switching from coal to oil; 20-35% reduction switching from coal to natural gas		Change in hardware to accommodate 100% fuel switch
Combined heat and power	All	Overall efficiency improves from 30-50% to 70-80%		$1,000-2,500/kW	High capital investment

VI. Energy Efficiency Improvements

This section presents the efficiency improvement measures identified for ICI boilers. The majority of the identified options focus on measures that are common from the perspective of applicability, availability, and owner/operator experience. Some options that may require project or site reconfiguration and process modifications, such as combined heat and power (CHP) and repowering, are also included in this section. Additional costs and complexities would need to be considered with these options. Options will vary for each unit and multiple options may be applied to save energy.

Efficiency gains derived from the various techniques or measures as well as the CO_2 benefit associated with such gains are summarized for each measure in the summary table. In many cases the impacts of these measures are highly site specific and benefits will vary. Ranges for potential benefits are listed when appropriate. Because boilers have different baseline efficiencies, it is easier to state efficiency gains in percentage points (e.g., from 78 to 83 % = 5 percentage points) rather than the actual efficiency gain as a percent improvement (e.g. from 78 to 83% = 1-78/83 = 6 %). Of course it is the actual percent efficiency gain that translates directly to CO_2 reduction. For purposes of providing nominal values in the summary tables, a baseline efficiency of about 78 % was used to relate efficiency gains in "percentage points" to CO_2 reduction potential as a fractional improvement as in the example above.

1. O&M Practices

Operating and maintenance (O&M) practices have a significant impact on plant performance, including its efficiency, reliability, and operating costs. Each of these parameters change over the life of the plant, and some deterioration of equipment is unavoidable. Boiler efficiency will decreases over time. The rate of deterioration can be curbed by good O&M practices. A well operated and maintained plant will experience less deterioration of boiler efficiency.

Deterioration results in higher heat rate, CO_2 emissions, and operating costs; in lower reliability; and in some cases, reduced output. After a few years of neglect, it may reach the point where significant investment is required to rehabilitate the plant and bring it as close as possible to the design performance. Such rehabilitation programs are capital intensive and typically O&M is covered in the budget of the plant for this reason.

Rehabilitation may focus on life extension and reliability improvement of the plant or may include additional measures that improve plant efficiency, occasionally above the original design efficiency. The efficiency can be improved by retrofitting combustion control technologies such as: heat recovery systems, control technology, and upgraded burners.

Additional GHG reductions can be achieved through energy improvements in the steam/hot water distribution system, the boiler auxiliaries, or in process efficiency improvements. (U.S. EPA, 2008)

1.1 *New Burners/Upgrades*

Older, wrongly sized, or mechanically deteriorated burners are typically inefficient. Inoperable dampers, broken registers, or clogged nozzles will render an otherwise good burner into a poor performer. These inefficiencies result in incomplete combustion (high carbon monoxide (CO) emissions and unburned carbon) and the need for high excess air. Burner maintenance, discussed above, is important because it can improve efficiency.

Burner upgrades will often need to consider controlling conventional emissions and multiple burners where the ability to maintain ideal air/fuel conditions is much more challenging. More sophisticated combustion monitoring and controls may be an integral part of an upgrade and are described as a separate measure in the section on tuning and optimization.

Burner replacement and retrofits can be considered on any burner. New burners for all types of boilers and fuels are commercially available. Burners with single and multiple fuel capability, low- and ultra low-NO_X models, and sizes ranging from very small to very large are widely deployed in industry. In addition, many suppliers (original equipment manufacturer (OEM) and non-OEM) offer burner retrofit parts for modifying burners rather than fully replacing them; this often can achieve significant improvements at lower cost than a full replacement. Site-specific conditions and objectives may favor one model over the other.

The potential for efficiency gains from new burners is a function of the difference between the old and new technologies. Levels of CO/UBC (incomplete combustion) and excess air between the new and old will dictate the performance improvement potential. Further, the burner size and turndown capability (i.e., ability to operate and/or efficiency of operation at less than full load) will impact the losses associated with inefficient low load and on/off cycling duty.

As an example, a natural gas burner requiring 2 percent excess oxygen (or 10 percent excess air) in the flue gas has an efficiency of about 84 percent. A less efficient burner, requiring 5 percent oxygen (O_2) (or about 25 percent excess air), has about an 83 percent efficiency for a 1 percent net lose in efficiency. For a coal-fired unit burning 10 percent ash coal, an unburned carbon (UBC or loss on ignition (LOI)) level of 20 percent would represent about a 2.5 percent fuel loss (Cleaver-Brooks, 2008; Ganapathy, 2003).

Finally, regarding size/turndown capability, most gas burners exhibit a turndown ratio, which is the ratio of capacity at full fire to its lowest firing point before shutdown, of 10:1 or 12:1 with little or no loss in combustion efficiency. However, some burners offer turndowns of 20:1 and up to 35:1 on oil. A higher turndown ratio reduces burner startups, provides better load control, saves wear-and-tear on the burner, and reduces purge-air requirements, all resulting in better overall efficiency (CIBO, 2003).

To illustrate potential savings, a 100 MMBtu/hr boiler, operating at an annual capacity factor of 45% or 400,000 MMBtu/yr, was considered with a combustion efficiency of 79%. At a price of $10/MMBtu, the annual fuel cost is $4 million. The savings from an energy efficient burner that improves combustion efficiency by 1 percent would be (EERE 2006a):

- Fuel Savings = [1 – current combustion efficiency (79)/improved combustion efficiency(80)] = 1.3 percent = 5,200MMBtu

- Annual Savings (at $10/MMBtu) = 5,200 × $10/MMBtu = $52,000

- For a new low NO_X burner upgrade package costing $250,000, a simple payback of about 5 years would result

- *Source: NESCAUM & MANE-VU, 2005*

Implementing this measure may be technically straightforward. Site-specific conditions and economic considerations must be addressed. As already mentioned, burner replacement/retrofits can be considered at all facilities. New burners for all types of boilers and fuels are commercially available. Replacement of burners may also be needed to comply with conventional emission regulations. For example, specifically for NO_X reductions, new low-NO_X burners and ultra-low-NOx burners offer the opportunity to comply with conventional emissions regulations as well as improve efficiency.

1.2 *Improved Combustion Measures*

There are a number of options for improving the combustion process and the overall performance of an ICI boiler. Although there is not a clear separation between them, for practical purposes they may be separated into the following groups:

- Combustion system tuning;

- Combustion and boiler performance optimization; and

- Instrumentation and Controls (I&C).

Combustion Tuning

One objective of the initial setting of the combustion system is to maximize the combustion efficiency (minimize UBC and CO emissions), and demands to minimize NO_X emissions may require further tuning. Also, the combustion system may drift over time from its optimum setting or certain controls (e.g., dampers) may not be operational due to wear.

Tuning of the combustion system requires a visual check by an experienced boiler or stationary engineer to ensure that everything is in good working condition and set according to the manufacturer's recommendations or the optimum settings developed for the particular boiler. Simple parametric testing may be required, which may involve changes in the key control variables of the combustion system and observation of key parameters such as CO emissions, steam outlet conditions, flue gas outlet (stack) temperature, and NO_X emissions.

Optimization

Optimization can be accomplished in a number of different ways. The most basic method has been described above and is based on parametric testing, analysis of the results, and estimating optimum operating parameters based on a given objective. The objective could be combustion efficiency (the measure of completeness of oxidation of the fuel), NO_X emissions, boiler efficiency (the ratio of net energy output divided by the energy input), plant efficiency, or a combination of these. For most ICI boilers, periodic testing and manual tuning are adequate. For larger boilers, especially ones that change operating conditions (e.g., load) frequently, it may be economical to install an optimization system. These are software-based systems that monitor and optimize boiler performance based on a user-specified objective within pre-set operating constraints.

Instrumentation and Controls

While optimization systems can function with whatever instrumentation and controls (I&C) are available at a facility, digital control systems are generally necessary to achieve the greatest improvement in performance through tuning and optimization. If the facility does not already have a modern control system, whether or not such a system is justified requires a site-specific assessment. The decision is highly dependent on the boiler size and the requirements of automation and monitoring, not only of the boiler, but of the overall facility.

Instrumentation requirements are subject to the same issues; there are no fixed requirements for instrumentation. In fact, very little instrumentation is essential to operate the boiler safely. However, if maximizing boiler efficiency or minimizing emissions (e.g., CO, NO_X, and CO_2) is required, certain instrumentation is justifiable, such as, temperature sensors, oxygen monitors. Additional instrumentation makes it possible to achieve better performance. For example, excess air (oxygen) is usually set based on the manufacturer's recommendations/guidelines with the objective to avoid incomplete combustion and maintain a stable flame. Usually, the excess air is set higher than required to ensure safe operation throughout the operating range of the boiler. As a result, 30 percent excess air may be set, when 15-20 percent may be adequate. If a CO monitor is installed, the boiler operator can fine-tune the process for uniform operation at minimum excess air without generating excess CO emissions.

One process control measure that has been used for ICI boilers is the use of oxygen trim controls. These controls measure the stack oxygen concentration and automatically adjust the inlet air at the burner for optimum efficiency. Manufacturers estimate that a 1 percent thermal efficiency can be achieved using this control.

Tuning, optimization and I&C are applicable to all boilers. However, optimization and I&C may not be economical in all cases. Usually, the larger the boiler, the more likely optimization and I&C could be justified. Also, coal or biomass fired boilers may be better candidates for optimization and I&C systems than natural gas-fired systems because their operating parameters (e.g., fuel quality) may be variable and difficult to control.

It is not easy to estimate efficiency improvement due to tuning, optimization, and I&C, as each of these approaches is site-specific and is affected greatly by the operating condition of the boiler (prior to implementing these measures), the type of fuel it burns, the number of control variables (set-points), etc. Typical estimates of efficiency improvement will be provided for illustration purposes. Combustion system tuning could reduce significantly CO emissions and UBC (in the case of coal- or oil-firing), with a CO reduction from 1000-2000 ppm to less than 200 ppm not considered unusual. In the case of coal-fired systems, UBC (in the flyash) may be reduced from 20-30 percent to 10-15 percent. The addition of optimization systems, modern controls systems, and instrumentation has resulted in efficiency improvement of 0.5 to 5.0 percentage points.

Tuning requires 1-2 days time of an experienced engineer. Cost estimates for tuning, optimization and I&C vary greatly. If the facility does not have an engineer, a consultant can be hired at a cost of $2,000 to $3,000. An optimization system, using neural network technology, ranges from $100,000 to $200,000 fully installed, calibrated, and tested. Annual technical support may be needed and could range from $10,000 to $30,000. The costs for modern control systems vary; for large boilers to install new I&C, the cost may exceed $1 million.

Implementing these measures may be technically straightforward and would require raising the awareness of facility staff and management regarding the potential cost savings and importance of tuning/optimization.

2. ***Air Preheat and Economizers***

For most fossil fuel-fired heating equipment, energy efficiency can be increased by using waste heat gas recovery systems to capture and use some of the heat in the flue gas. The most commonly used waste heat recovery methods are preheating combustion air and water heating. Heat recovery equipment includes various type of heat exchangers (economizers and air heaters), typically located after the gases have passed through the steam generating sections of the boiler.

Air heaters transfer heat from the flue gas to the incoming combustion air. In low-pressure gas- or oil-fired boilers, air heaters function simply as gas “coolers,” as there is no need to preheat the oil or gas in order for it to burn. Pulverized coal-fired boilers require the use of air preheaters to evaporate the moisture in the coal. This heated air also serves to transport the pulverized fuel to the burners. Stoker-fired boilers typically do not require preheated air unless the moisture content of the coal exceeds 25 percent (CIBO, 2003; Clever-Brooks, 2008).

There are two general types of air preheaters (APH): recuperators and regenerators. Recuperators are gas-to-gas heat exchangers usually placed on the boiler stack. Internal tubes or plates transfer heat from the outgoing exhaust gas to the incoming combustion air while keeping the two streams from mixing. Regenerators include two or more separate heat storage sections, each referred to as a regenerator. The hot flue gas heats the heating plates; in turn, this heat is transferred to the incoming combustion air.

Air preheaters are widely used in large boiler applications (as in the electric utility sector). In the ICI sector, APH are not as widely used as they were in the past due to more recent

NO_X regulations (the higher temperature of the combustion promotes NO_X formation). Hence, many gas and liquid fuel boilers do not have APH. Economizers are favored in these cases, as they do not adversely impact the combustion air temperature and the resulting NO_X formation.

Economizers are basically tubular heat transfer surfaces used to preheat boiler feedwater before it enters the steam drum or furnace surfaces. Economizers also reduce the potential of thermal shock and strong water temperature fluctuations as the feedwater enters the drum or waterwalls.

Similar to all gas/air handling equipment, economizers and APH will impose some pressure loss on the system. Therefore, when considering the potential for an economizer or APH retrofit application, an analysis of the existing fan capacities is required. Also, reducing flue gas temperatures close to or below acid dew point incurs condensation/corrosion concerns that must be addressed on a case-by-case basis.

The general benefits of lowering flue gas temperature through combustion air preheating include: energy improvement from recovering the wasted flue gas heat; faster boiler startups; and in the case of solid fuels, the evaporation of moisture prior to combustion. Typical gains are approximately 1 percent efficiency gain per 40 °F decrease associated with flue gas temperature.

Retrofitting an APH to a natural gas-fired 10 MMBtu/hr boiler, operating at an annual capacity factor of 68percent and with a flue gas temperature of 600 °F, to reduce the temperature by 300 °F results in an efficiency improvement from about 76 percent to 82 percent. With a price of $10/MMBtu, the annual fuel cost is $600,000. The savings associated with this potential improvement would be as follows:

- Fuel Savings = (1 – 76/82.2) = 7.5 percent = 4,500 MMBtu
- Annual Savings (at $10/MMBtu) = 4,500 × $10/MMBtu = $45,000
- Based on an estimated cost for an APH system of $200,000 to $250,000, a payback of less than 5 years would result (CIBO, 2003)
- The economizer recovers heat from the boiler exhaust gas and is used to pre-heat the boiler feed water. Capturing this normally lost heat reduces the overall fuel requirements for the boiler. This is possible because the boiler feed-water or return water is pre-heated by the economizer; therefore, the boiler’s main heating circuit does not need to provide as much heat to produce a given output quantity of steam or hot water. Manufacturers specify the total thermal efficiency of the economizer system to be 5 percent (U.S. EPA 2008). For a large boiler (650 MMBtu/hr or about 500,000 lb steam/hr), an estimated cost for an economizer was $2.3 million.

Implementing this measure may be relatively technically straightforward. Site-specific conditions and economic considerations must be addressed. Availability of space can be a barrier to the retrofit of an air preheater or an economizer. Some ICI boilers may be installed in very congested areas and within existing buildings. The issue of retrofit downtime is a common barrier throughout this report for all measures requiring offline implementation. Also, for any boiler with a remaining operating life of less than 10-15 years, the economics may not be favorable, especially if downtime is considered (Ganapathy, 2003).

3. Turbulators for Firetube Boilers

In firetube boilers, the hot combustion gases travel across the boiler heat-exchange surfaces several times. Each time this occurs is commonly called a "pass" and boilers are typically categorized by the number of "passes." For example, a two-pass boiler provides two opportunities for hot gases to transfer heat to the boiler water. Within the tubes, the combustion gas typically changes from a turbulent flow regime when it enters the tubes, to a laminar regime, with its boundary layer of cooler gas along the tube walls. This boundary layer has a well known, negative impact on heat transfer.

In simple terms, turbulators help to regain the heat transfer characteristics of a turbulent flow regime by creating "turbulence" within the tubes. Physically, turbulators are simple devices (baffles, blades, coiled wire) that are inserted in the gas tubes to "break-up" the laminar boundary layer, resulting in the increased convective heat transfer. The result is that the flue gas exits at a lower temperature, and boiler efficiency is improved. For firetube boilers, turbulators are a cheaper alternative to economizers and APHs (Ganapathy, 2003).

Current turbulator designs do not cause a significant increase in pressure drop or contribute to soot formation in natural gas-fired boilers. Turbulators can also help balance gas flow through the tubes, thereby minimizing thermal stratification within the tubes (EnerCon, 2008).

As already stated, the use of turbulators is intended for firetube boilers. Firetube boilers are primarily gas- or oil-fired. Within this group, older boilers that were typically designed with a lesser number of passes than newer firetube boilers, are most suitable for the application of turbulators. This is because multi-pass boilers are inherently more efficient due to the significantly higher heat transfer surface area. Turbulators are usually installed on the last boiler pass.

Efficiency improvement from the application of turbulators derives from the increased heat transfer from the flue gas and resulting lower flue gas exit temperature. This efficiency improvement is approximately 1 percent per 40 °F of gas temperature reduction.

Turbulators are substitutes for more costly economizers or APH. They are simple, easy to install, and low cost. Installed cost is about \$10 to \$15 per boiler tube (EERE, 2006b). As an example, consider a 10 million Btu/hr firetube boiler, operating 100,000 MMBtu/yr, installing a total of 250 turbulators into its firetube boiler, resulting in a reduction in the stack gas temperature of 130 °F and increasing boiler efficiency from about 79 to 82 percent.

- Fuel Savings = (1 – 79/82.3) = 4 percent or 4,000 MMBtu

- Annual Savings (at \$10/MMBtu) = 4,000 MMBtu × \$10/MMBtu = \$40,000

- Simple payback at \$15/tube = \$3,750/\$40,000 ~ 0.1 years (less than 2 months)

Implementing this measure may be technically straightforward. For firetube boilers, especially older types, the application of turbulators is well understood and widely applicable. Compared to the previously discussed APH and economizer, turbulators may result in a shorter payback period for firetube boilers.

4. Boiler Insulation

Due to the large size of many ICI boilers, the surface area of the outer surface of the boiler is very high, and significant heat loss can occur through the boiler shell. Proper insulation is important to keep these losses to a minimum. The refractory material lining the boiler is the primary insulating material.

When replacing refractory materials at existing plants, structural considerations must be taken into account to assure the boiler can support the weight of the new refractory material. New construction can account for the weight of the refractory material in the industrial boiler design. The quantity of heat lost in this manner is fairly constant at different boiler firing rates and, as a result, becomes an increasingly higher percentage of the total heat losses at the lower firing rates. The radiation loss at high firing rates varies from a fraction of one percent up to two percent, depending on the capacity of the boiler.

Insulation is any material that is employed to restrict the transfer of heat energy. It can generally be categorized as either mass or reflective type depending on whether it is aimed at reducing conductive or radiative heat transmission, respectively. Properly applied insulation can result in large savings in energy losses depending on type, thickness, and condition of the existing insulation. Bare surface temperature in boilers ranges from saturation temperature on exposed tube surfaces to air and gas temperatures on duct surfaces. Radiation losses tend to increase with decreasing load and can be as high as 7 percent for small units or larger units operating at reduced loads.

Implementing this measure may be technically straightforward. Procedures have been developed by the Thermal Insulation Manufacturers Association to determine the optimum insulation thickness for various applications based on:

- fuel costs;

- operating temperatures;

- insulation type;

- depreciation period of plant and insulation; and

• capital investment.

5. Minimization of Air Infiltration

Air infiltration is an undesirable, but unavoidable, concern in boiler systems and ductwork. This occurs as a result of the large temperature difference between the hot combustion gases and ambient air temperature, which creates a negative pressure in the furnace. This is often called “stack effect” or “thermal head.” This negative pressure also occurs in balanced draft systems where an induced draft fan is used.

The sources for air leaks can be multiple, ranging from small openings (such as warped doors which deteriorated and no longer provide adequate sealing) to actual cracks in boiler casings or ductwork requiring more significant repairs. Indicators of excessive air leakage include: high O_2 levels measured at the outlet of the boiler, as well as fuel consumption and gas temperatures. Depending on the severity and source of the leaks, the solution can be as simple as routine maintenance (e.g., adjust door seals), or requiring more thorough fixes during planned outages (e.g., repair boiler casing cracks). Maintenance of boiler systems to keep air leakage under control is an applicable and universally applied approach. It requires a combination of good maintenance procedures, as well as operational monitoring that can identify air leakage conditions and sources.

The resulting impact of air leakage is similar to operating the boiler with too much excess air; it is a source of energy loss due to the unnecessary air being heated and wasted. The amount of leakage is a function of many parameters, starting with the size of the openings, but also includes the gas temperature, pressure, and velocity. The opportunity for improvement is a function of the leakage reduction and associated reduction in excess air.

The efficiency impacts can be significant. For example, a 3 percent change in O_2 in a gas-fired boiler represents a gain of almost 4 percentage points in efficiency improvement. Expected efficiency improvement from reducing air leakage problems in ICI boilers are in the range of 1 to 4 percent.

It is difficult to address the cost of reducing air leakage, as this can range from essentially routine maintenance procedures to more costly repairs. However, in general, the cost/benefit to minimizing air leakage should provide good value.

Implementing this measure may be technically straightforward. Site-specific operating needs and economic considerations must be addressed. Major repairs resulting in boiler downtime and/or capital costs can result.

6. Boiler Blowdown Heat Exchanger

Blowdown is required to maintain water quality. Depending on site-specific conditions and make-up water quality, blowdown rates may vary greatly. Unfortunately, the blowdown still contains energy, which could otherwise be used instead of being wasted. This waste heat can be recovered with a heat exchanger, a flash tank, or flash tank in combination with a heat exchanger. The resulting low-pressure steam is most typically used in deaerators. Cooling the blowdown has the additional advantage of reducing the temperature of the liquids released into the sewer system.

Blowdown can be either intermittent bottom blowdown or continuous blowdown. Intermittent bottom blowdown may be sufficient if the feedwater is exceptionally pure. Intermittent blowdown is performed manually and therefore may result in wide fluctuations in blowdown patterns. Use of continuous rather than intermittent blowdown saves treated boiler water and can result in significant energy savings.

The higher the blowdown rate and boiler pressures, the more attractive the option of recovering the blowdown becomes. Any boiler with continuous blowdown exceeding 5 percent of the steam rate is a good candidate for considering blowdown waste heat recovery. Manufacturers specified that a 1 percent thermal efficiency can be achieved by this method (U.S. EPA, 2008). In certain cases, significant energy savings can be accomplished by recovering heat from boiler blowdown. For example, an efficiency improvement of over 2 percent can be achieved at a 10 percent blowdown rate on a 150 psig boiler.

Site-specific conditions and economic considerations must be addressed to determine whether this measure involving heat recovery is technically and economically viable; it is necessary to consider its viability on a case-by-case basis.

7. Condensate Return System

Hot condensate that is not returned to the boiler represents a corresponding loss of energy. Other benefits that will accrue from an efficient condensate return system are less make-up water, water related treatment costs, boiler blowdown, and disposal costs. Energy savings come about from the fact that most condensate is returned at relatively hot temperature (typically 130 to 225 °F), compared to the cold makeup water (50 to 60 °F) that must be heated. A return condensate system must be a function of the specific boiler and water/condensate quality, but essentially involves a new distribution line configuration.

Condensate line return is applicable to all boiler types that do not already include return of hot condensate. The larger the unit and the hotter the condensate return, the more benefit will accrue. This measure is commercially available and used in industry. The condensate quality or purity is an important consideration on a case-by-case basis and should be considered when determining the appropriate quantity of condensate return.

The energy savings is the energy contained in the condensate being returned. In practice, the total amount of steam returned must account for the “steam flash loss” - the amount of saturated condensate that flashes off to steam when reduced to a lower pressure. The energy efficiency improvement for a particular boiler is, therefore, the ratio of Btu/hr saved from the condensate return to the original Btu/hr heat input to the boiler. Overall cost savings accrue from the fuel savings due to the efficiency improvement, plus the value of the reduction in the cost of make-up water, sewage disposal, and water treatment chemicals.

Site-specific conditions and economic considerations must be addressed to determine whether it would be applicable, and, therefore, it is necessary to consider its viability on a case-by-case basis. A further improvement on recovering the available energy of the condensate may be to use a heat exchanger (vent condenser) where the flashing steam is typically vented. Site-specific evaluation is necessary before determining the viability of this approach.

8. Refractory Material Selection

The refractory bricks lining the combustion zone of the boiler protect the outer shell from the high combustion temperatures, as well as chemical and mechanical stresses. Although the choice of refractory materials is highly dependent on fuels, raw materials, and operating conditions, consideration should be given to refractory materials that provide the highest insulating capacity and have the longest life. Although benefits may be difficult to quantify due to the unique conditions at each facility, some energy savings will be realized from higher quality refractory materials.

9. Minimization of Gas-Side Heat Transfer Surface Deposits

Boiler heat transfer surfaces are exposed to high temperature gases and products of combustion, which vary in composition amongst different fuels and operating conditions. Formation of soot, ash products from solid and liquid fuels, and incomplete combustion of carbon all contribute to the potential for surface deposits. Oxides may also be formed on the surface of the tubes. These deposits are further related to operational issues ranging from malfunctioning burners, to the condition of the heat transfer surfaces, to gas flow patterns within the boiler combustion zone.

To minimize deposition problems (slagging and fouling), it is important to operate the boiler within the parameters for which it was designed. This imposes a number of operational issues, such as fuel quality restrictions and firing rates, among others. However, systems firing ash-laden fuels also include “cleaning” systems (soot blowers that typically use compressed air or steam) to periodically remove the unavoidable deposition on the boiler walls and tubes. In addition, many units utilize “fuel treatment” to mitigate the deposition propensity of the ash and products of combustion. Many such products are available and typically modify the characteristics of the ash (e.g., the temperature–viscosity relationship) to minimize deposition.

More advanced soot blowing systems, or Intelligent Sootblowing Systems (ISS), use feedback signals, such as exit gas temperature or heat transfer sensors, to trigger their operation. ISS determines which soot blower needs to be operated and when, depending on the local performance of the heating surfaces, resulting in optimization of operations and effectiveness. In more extreme cases and when more severe changes in fuel quality occur, it is possible that the existing soot blower system may not be sufficiently adequate to remove the deposits and changes to the ISS may be required.

Keeping heat transfer surfaces clean is essential for efficient boiler operation. As would be expected, solid fuels are the most common application for soot blowing systems. Although oil and gas units occasionally have to address deposition of soot/slag, they typically do not employ these systems. The choice of an appropriate soot blowing system is boiler and fuel dependent, as discussed above. Soot blowing systems are widely used in industry.

Advances in soot-blowing system controls have become more widespread, especially in large coal-fired boilers due to the direct relationship between NO_X formation and combustion temperature. In this case, optimizing the soot blower operation minimizes gas temperatures and yields not only efficiency benefits but also NO_X emission reductions.

The relationship between deposits and heat transfer deterioration varies with the type of fuel and ash characteristics. For example, similar thickness layers of ash deposits will have different impacts on heat transfer based on the refractory characteristics of the individual ashes. The extent to which dirty heat transfer surfaces affect efficiency can be estimated from an increase in stack temperature relative to a "clean operation" or baseline condition. Efficiency is reduced by approximately 1 percent for every 40 °F increase in stack temperature. Changes in exit gas temperatures of over 120 °F due to boiler slagging and fouling would correspond to about a 3 percent decrease in efficiency. Efficiency gains of 1 to 3 percent may be gained within the ICI boiler population by minimizing boiler surface deposition. Excessive slagging also may affect the outlet steam conditions of the boiler, resulting in reduced steam temperature or the requirement for attemperation sprays.

The cost of reducing boiler deposition can range from essentially routine maintenance procedures to soot-blower system retrofits. However, in general, the cost/benefit to minimizing deposition should provide good value. Soot blower costs vary by type (i.e., wall blowers, water cannon, retractable lances). Typical costs are in the range of $50K to $125K for a single soot blower, with wall blowers being typically the least expensive and retractable lances the most costly. Installation costs will typically double these numbers.

Implementing this measure may be relatively straightforward where boiler deposition mitigation work practices already exist or can be readily incorporated as part of boiler maintenance. Therefore, training and enhanced operating procedures may be needed. Retrofit of more advanced or robust soot blowers will require down time and capital cost. Site-specific operating needs and economic consideration must be addressed.

10. Steam Line Maintenance

Heat loss through uninsulated lines and fittings can be significant. For example, 250 ft of uninsulated, 4-inch line with 300 psig steam would yield 2800 MMBtu/yr, the equivalent of about 0.3 to 1.2 percent heat loss for boiler sizes between 25 and 100 MMBtu/hr. Similarly, the penalties for leaky valves/traps can represent measurable losses. General experience suggests that steam systems that do not include steam trap maintenance, over a period of 3 to 5 years can result in 15 to 30 percent steam trap failures. In plants that have a regular steam trap inspection and maintenance program, leaking traps should account for less than 5 percent of trap population.

Energy audits and maintenance procedures should highlight common maintenance items such as uninsulated steam distribution and condensate return lines and other fittings. Ensuring that all steam/condensate lines are properly insulated will yield measurable efficiency gains. Common practice suggests that surfaces over 120 °F (steam and condensate return piping, fittings) should be insulated. Insulating jackets are available for valves, traps, flanges and other fittings. Leaky steam traps should be fixed as they represent another potentially significant source of wasted energy.

Implementing this measure may be technically straightforward. These insulation and leaks mitigation measures are universally applied and require only a dedicated awareness of line conditions (routine surveys).

VII. Energy Programs and Management Systems

Industrial energy efficiency can be greatly enhanced by effective management of the energy use of operations and processes. Management of operations can be guided by the U.S. EPA's ENERGY STAR Program or ANSI or ISO standards.

U.S. EPA's ENERGY STAR Program works with hundreds of U.S. manufacturers and has demonstrated that companies with stronger energy management programs gain greater improvements in energy efficiency than those without practices focused on continuous improvement of energy performance.

Energy Management Systems (EnMS) provides a framework for managing energy and promote continuous improvement. The EnMS provides the structure for an energy program and its energy team. EnMS establish assessment, planning, and evaluation procedures which are critical for actually realizing and sustaining the potential energy efficiency gains of new technologies or operational changes.

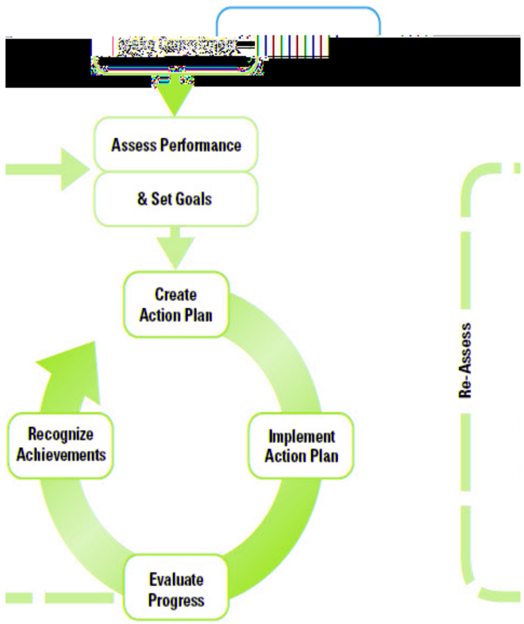
Energy management systems promote continuous improvement of energy efficiency through:

- Organizational practices and policies,
- Team development,
- Planning and evaluation,
- Tracking and measurement,
- Communication and employee engagement, and

- Evaluation and corrective measures.

For nearly 10 years, the U.S. EPA's ENERGY STAR Program has promoted an energy management system approach. This approach, outlined in the graphic below, outlines the basic steps followed by most energy management systems approaches.

ENERGY STAR Guidelines for Energy Management



(www.energystar.gov/guidelines)

In recent years, interest in energy management system approaches has been growing. There are many reasons for the greater interest. These include recognition that a lack of management commitment is an important barrier to increasing energy efficiency. Further, lack of an effective energy team and program results in low implementation rates for new technologies or recommendations from energy assessments. Poor energy management practices that fail to monitor performance do not ensure that new technologies and operating procedures will achieve their potential to improve efficiency.

EPA's ENERGY STAR Guidelines for Energy Management are available for public use on the web and provide extensive guidance (see: www.energystar.gov/guidelines). Alternatively, energy management *standards* are available for purchase from ANSI, ANSI MSE 2001:200 and in the future from ISO, ISO 50001.

Energy management systems can help organizations achieve greater savings through a focus on continuous improvement. Companies will need to combine effective plant energy benchmarking and appropriate plant improvements to achieve energy savings.

There are a variety of factors to weigh when considering certification to an Energy Management Standard established by a standards body such as ANSI or ISO. First, energy management system standards are designed to be flexible. A user of the standard is able to define the scope and boundaries of the energy management system so that single production lines, single processes, a plant or a corporation could be certified. Achieving certification for the first time is not based on efficiency or savings (although re-certifications at a later time could be). Finally, cost is an important factor to weigh when using the standards. Internal personnel time commitments, external auditor and registry costs should be considered.

Overall, a systems approach to energy management is an effective strategy for encouraging energy efficiency in a facility or corporation. There are multiple pathways available with a wide range of associated costs. The effectiveness of an energy management system is linked directly to the system's scope, goals, measurement and tracking.

1. Sector-Specific Plant Energy Performance Benchmarks

Plant energy benchmarking is the process of comparing the energy performance of one site against itself over time or against the range of performance of the industry. Plant energy benchmarking is typically done at a whole-facility or site level in order to capture the synergies of different technologies, operating practices, and operating conditions.

Benchmarking enables companies to set informed and competitive goals for plant energy improvement. Benchmarking also helps companies prioritize where to make investment to improve performance of poor performers while learning from the approaches used by top performers.

When benchmarking is conducted across an industrial sector, a benchmark can be established that defines best in class energy performance. The U.S. EPA's ENERGY STAR Program has developed benchmarking tools that establish best-in-class for specific industrial sectors. These tools, known as Plant Energy Performance Indicators (EPI) are established for specific industrial sectors and are available for free at www.energystar.gov/industrybenchmarkingtools. Using several basic plant-specific inputs, the EPIs calculate a plant's energy performance providing a score from 0-100. EPA defines the average plant within the industry nationally at the score of 50; energy-efficient plants score 75 or better. ENERGY STAR offers recognition for sites that score in the top quartile of energy efficiency for their sector using the EPI.

2. Industry Energy Efficiency Initiatives

The U.S. EPA's ENERGY STAR Program (www.energystar.gov/industry) and U.S. Department of Energy's Industrial Technology Program (www.energy.gov/energyefficiency) have led industry specific energy efficiency initiatives over the years. These programs have helped to create guidebooks of energy efficient technologies, profiles of industry energy use, and studies of future technologies. Some States have also lead sector specific energy efficiency initiatives. Resources from these programs can help identify technologies that may reduce CO_2 emissions.

VIII. *Carbon Capture and Storage*

Carbon capture and storage (CCS) involves separation and capture of CO2 from the flue gas, pressurization of the captured CO_2, transportation of the CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. Several different technologies, at varying stages of development, have the potential to separate and capture CO_2. Some have been demonstrated at the slip-stream or pilot-scale, while many others are still at the bench-top or laboratory stage of development.

In 2010, an Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated Federal strategy to speed the commercial development and deployment of clean coal technologies. The Task Force was specifically charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration projects online by 2016. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical barriers to implementation. The development status of CCS technologies is thoroughly discussed in the Task Force report. For additional information on the Task Force and its findings on CCS as a CO_2 control technology, go to: http://www.epa.gov/climatechange/policy/ccs_task_force.html.

IX. Other Measures to Reduce GHG Emissions

1. *Alternative Fuels – Biomass*

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Pure biomass fuels include animal meal, waste wood products and sawdust, and sewage sludge. It may also be possible to use biomass materials that are specifically cultivated for fuel use, such as wood, grasses, green algae, and other quick growing species.

There are a number of issues related to the use of biomass fuels:

- Caloric Value - Most organic materials have a caloric content less than traditional fossil fuels.

- Trace compounds - The biomass fuel, particularly waste products, may contain trace elements such as heavy metals or may contain compounds that are detrimental such as chlorine. These substances could result in other air emission issues.

- Waste regulations - The regulation of wastes that may be used for fuel, or the types of units that the material may be utilized in, affects the use of those wastes as fuel. For example, if there are no impediments to landfilling the waste, then there may be little of the waste available for fuel use.

- Social acceptance - The use of waste fuels in a given area may be driven by social acceptance of burning the fuel in the community.

- Agricultural areas - For crops grown for biomass purposes, sufficient agricultural areas in proximity to the industrial boiler are required.

2. Co-firing

"Co-firing" refers to the case of burning more than one fuel in one boiler. As such, gas ("gas co-firing") could be burned in a boiler designed for oil or coal. Also, biomass (in solid form) could be co-fired in a boiler designed for coal. Finally, liquid or gas biofuels may be co-fired in all types of boilers.

Biomass may include switchgrass, sawdust, wood wastes, municipal solid wastes, non-recyclable paper, pulp mill sludge, chicken manure and other waste fuels. Typically, biomass has been limited to a maximum of 20 percent of the total plant input, and in most cases, between 3 and 12 percent. However, the pulp and paper industry has decades of experience co-firing up to 50 percent biomass with coal (DOE, 2004). Boilers could be designed specifically to accommodate biomass combustion or existing boilers could be modified; the industry has experience with both.

Gas co-firing involves modification of the combustion system to accommodate the introduction of natural gas or biomass-derived gas. The co-fired fuel is injected directly into the combustion zone.

In case of biomass co-firing in boilers burning coal, the techniques can be classified either as *direct* or *indirect*. Direct firing involves mixing of the biomass before the pulverizers ("co-milling" or blending) or direct injection (separate feed system for the biomass fuel). Indirect firing consists of separate boilers for the primary fuel and for biomass linked by a common connection to the steam cycle (may share the same steam generator and steam turbine).

From the five model plants identified for industrial applications, the models burning solid fuels (PC, circulating fluidized bed, and stoker) are clearly suitable to co-fire natural gas, biofuels, and (solid) biomass. The watertube and firetube boilers burning oil can accommodate biofuels and natural gas.

Co-firing of natural gas or biofuels does not present any technical issues which cannot be addressed through appropriate design. In most cases, the issues associated with these fuels relate to economic attractiveness, availability of biofuels, and availability of natural gas at the plant site.

In the case of biomass co-firing, retrofits face a number of issues, mainly related to the key characteristics of biomass compared to coal:

- Biomass has lower density; hence it is bulkier and affects the fuel handling equipment (pulverizers, fuel transport and fuel feed systems).

- High moisture content, above 40 percent, increases the time required for complete combustion and affect boiler efficiency.

- Biomass is more volatile than coal; biomass contains up to 80 percent volatile matter (on a dry-weight basis) compared to a maximum of 45 percent for coal; hence it is easier to self-ignite.

- High alkali biomass may contribute to formation of alkali sulfates, which make it easier to clean the boiler heating surface through sootblowing.

- Biomass degrades over time, which means that it cannot be stored for long periods of time.

- Biomass may contain high concentration of chloride, causing corrosion, especially if sulfur is also present in the fuel (either in the biomass or the coal).

However, all these issues can be addressed through appropriate design and operation. The same issues are being faced by new plants, but in this case, it is easier to adjust the initial design to accommodate co-firing.

The impact on efficiency of co-firing gas in existing boilers is expected to be minor (less than 0.5 percentage point). Depending on the composition of the co-fired fuel vs. the fuel it is replacing; fuel with high concentrations of H_2 and moisture would have an adverse impact on plant efficiency. The impact of biomass co-firing in coal-fired boilers could result in a reduction of up to 2 percentage points in boiler efficiency and up to 1 percentage point in plant efficiency.

With regards to CO_2 emission reductions:

- Gas co-firing has a beneficial impact in the case where it replaces coal; this is mainly because the carbon content of the coal is higher than gas; a 20-30 percent reduction in CO_2 is typical.

- Estimating the impact of biofuels on CO_2 emission requires a process-specific assessment.

Other impacts due to biomass co-firing:

- Usually there are no impacts on plant output and reliability, assuming the right precautions are taken in designing and operating the facility.

- SO_2 and mercury are reduced proportionally to the biomass or gas input because these fuels contain less sulfur or mercury.

- NO_X emission reduction is usually greater than the percentage of biomass or gas heat input. If the co-firing system is designed to be also a "reburning" system (introduction of fuel above the primary combustion zone), NO_X reduction of up to 30 percent could be achieved.

There is significant industry experience in co-firing in all types of boilers (PC, FBC, cyclone and stokers) ranging from 1 to 700 megawatt (MW). The pulp and paper industry has been co-firing for decades. In the 1990s, many power plants demonstrated this option in Europe, Japan, and the United States, and then proceeded to use it commercially.

The most common issues and barriers associated with co-firing are:

- Availability of natural gas on site; if it is not available, it may be too costly to extend a gas pipeline to reach the site. However, this is expected to affect a very small number of facilities, as the natural gas distribution in the US is well-developed and reaches most locations.

- Price of the co-fired fuel; natural gas is highly affected by oil and gas market conditions. Biofuels depends on the production process, the price of the biomass feedstock and potential regulatory incentives (tax breaks, etc.). Finally, biomass is site-specific, may vary significantly, and may increase in cost after the co-firing project is implemented.

- Availability and logistics for biomass collection and transportation.

3. *Fuel Switching*

Fuel switching refers to a change in the plant hardware to accommodate complete (100 percent) replacement of one fuel with another fuel. Fuel switching from a coal-, fuel oil-, or diesel-fired boiler to a natural gas-fired boiler can result in decreased emissions (U.S. EPA 2008). Considering that the focus of this report is to identify CO_2 reducing options, the following fuel switching options are of interest:

- Coal could be switched to oil, natural gas or coal-derived gas; and

- Oil could be switched to natural gas or coal-derived gas.

<u>Fuel Switching in Coal-fired Systems</u>

Switching from coal to another fuel is feasible and has been put into practice in several cases. Economics and other issues are most often the reason such switching is not taking place. Switching from coal to oil is feasible and has occurred in the US, especially in the 1960s when oil was inexpensive. If such a change would be desirable, the required hardware changes include:

- Construction of oil storage; if there is existing oil storage, it may not be adequate and a larger storage capacity would need to be provided.

- Replacement or modification of the burners.

- If the same output of electricity or steam is required, additional hardware modifications may be required. While such changes are site-specific, coal-fired boilers are usually larger than oil-fired; the cross sectional area of a coal-fired boiler is about 20 percent larger and the boiler is about 33 percent taller than an oil-fired boiler (Llinares and Smith, 1980). As a result, burning oil in a larger furnace most likely would not produce the same amount of steam, or steam with the same temperatures. If the output conditions need to be maintained, more extensive boiler modifications would be required.

Switching from coal to natural gas presents similar issues as a switch to oil. The cross sectional area of a coal-fired boiler is about 50 percent larger and the boiler is about 60 percent taller than a gas-fired boiler (Richards, 1978). The only differences between switching to natural gas and to oil are:

1. The extent of the boiler modifications, which is design-specific.

2. There is no need for natural gas storage, as gas is usually provided directly from a gas pipeline. However, there are plants which may not have access to natural gas and may need to invest in bringing a gas pipeline into the plant.

Switching from coal to coal-derived fuels is also practical, but its viability requires very site-specific assessment. First, the potential for CO_2 reduction depends on the coal-derived gas production process and needs to consider all the emissions released throughout the fuel chain (including coal mining, coal transport, conversion from coal to gas-derived fuel and utilization in the industrial boiler). In terms of an existing industrial boiler accommodating the coal-derived gas, the considerations are similar as those required for a switch to natural gas.

Switching from coal to biofuels (of either gas or liquid form) would involve similar considerations as the switch from coal to oil and natural gas.

Switching from coal to biomass requires:

- Replacement of the fuel storage, handling and feed system; some equipment from the coal system may also be usable for biomass. Space is not likely to be a constraint, because the space available for storage and handling of the coal is likely to be adequate for biomass.

- Depending on the boiler design, some modifications may be required to maintain plant output conditions. Biomass firing typically occurs in either stoker or fluidized bed boilers. This requires a site-specific assessment.

<u>Fuel Switching in Oil-fired Systems</u>

Switching from oil to natural gas would involve:

- Making sure that a natural gas supply is available; if a gas pipeline is not available at the plant site, a pipeline extension may be required.
- Replacement or modification of the burners.
- Some modifications of the boiler are likely to be required to maintain the same output of electricity or steam. However, the boiler modifications are generally not expected to be as extensive as in the case of coal to gas switching.

Switching from oil to coal-derived gas or biofuels (in gaseous form) is similar to natural gas. The only difference is that CO_2 emissions would need to consider all CO_2 emissions released throughout the fuel chain (including coal mining, coal transport, conversion from coal to gas-derived fuel, and utilization in the industrial boiler).

Switching from oil to liquid biofuels is the easiest option in terms of required modifications to the plant hardware and potential impacts on plant performance. However, the CO_2 emissions would need to consider all fuel-chain impacts.

Switching from oil to biomass entails similar modifications as in the case of a coal to biomass switch. Some differences are noteworthy:

- In some sites, space to accommodate the biomass may be an issue; oil-firing facilities only require an oil storage tank, while biomass would require significant storage area, as well as space for drying and crushing prior to being fed into the boiler.
- Oil-fired boilers are compact relative to biomass-firing boilers; hence, it is likely that the boiler would not be able to maintain the plant output even after significant modifications.

For the purposes of this report, it is assumed that oil to biomass switch is not attractive.

Switching of PC plants to any of the fuels mentioned above is feasible and the industry has relevant experience (switching from coal to oil occurred in the 1960s, and from coal to gas in the 1980s and 1990s). Switching to coal-derived gas or biofuels has similarities with switching to natural gas and oil, respectively. Also, there is adequate experience in boiler modifications to accommodate biomass.

Switching of FBC to oil, gas, coal-derived gas, or biofuels is not feasible, as the circulating fluidized bed requires solid materials to ‘build up the bed.” FBC are suitable candidates to switch to biomass.

It is theoretically and practically viable to switch stoker boilers to burn oil, gas, coal-derived gas, or biofuels. However, the overall design of stokers results in significantly lower efficiency than other prime movers (e.g., gas turbines and diesel engines), which can burn these fuels more efficiently. Stokers can easily accommodate biomass fuels.

Watertube and firetube boilers that use oil and natural gas, are suitable only for clean liquid or gaseous fuels. As a result, an oil-fired boiler could be switched to gas or coal-derived gas or biofuel. In addition to the burners which would need to be replaced, some additional modifications may be needed depending on the design of the existing boiler and the properties of the fuels. Gas-fired boilers would have less of an incentive to switch to coal-derived gas or biofuels, unless the price differential is adequate to justify the investment in the design modifications.

Efficiency change due to fuel switching is the result of the composition of the fuel and the design of the plant (as it exists, plus potential modifications which can be made). Considering that each fuel has different carbon content, this results in different amount of CO_2 emissions, as illustrated by the following typical emission factors (EIA, 2008).

	lbs/MMBtu
• Natural Gas (pipeline quality):	117.080
• Distillate oil (No. 1, 2 and 4, as well as diesel):	161.386
• Residual Oil (No. 5 and 6):	173.906
• Bituminous coal:	205.300
• Subbituminous coal:	212.700
• Lignite:	215.400

Hence, switching from coal to oil would result in a 20 to 35 percent CO_2 reduction (depending on the composition of the coal and the oil), and a 40 to 50 percent reduction in the case of switching from coal to natural gas.

Plant efficiency improvements depend greatly on the existing plant design and design modifications implemented as part of the fuel switching project. However, the efficiency changes due to design modifications are expected to be much smaller than the impact of the fuel composition.

In addition to CO_2 emission impacts, switching to another fuel may have an impact on the other pollutants (particulates, SO_2, NO_X, and mercury). Switching from coal or oil to other fuels reduces particulates and, in most cases (natural gas, biofuels and biomass), SO_2 emissions; the exact percentage SO_2 reduction depends on the sulfur content of the coal or oil. NO_X emissions depend on the design of the boiler, but some NO_X reduction is expected as a result of fuel switching.

Barriers to fuel switching include:

- Cleaner fuels are usually more expensive. Potential incentives include: tax breaks for investments; fuel subsidies; allowances for reduction of emissions (presently applicable to SO_2 and NO_X); and in the future, carbon credits.

- The design modifications require shut-down of the plant for a few weeks or months; such interruption is difficult for industrial facilities which are used to operating without interruption, and very often, 24 hours per day.

- Site-specific barriers such as a lack of space or feedstock (for biomass systems) and lack of natural gas on site (in those cases where a switch to gas is desirable.

4. Combined Heat and Power

CHP, or cogeneration as it is commonly called in the US, involves production of useful heat and electricity from a single facility. There are significant efficiency gains to be derived from employing CHP. Thermal electric generation processes lose 50-70 percent of the input fuel energy in the form of waste heat. Recovering this energy for steam or hot water production on-site or at a nearby facility increases the overall efficiency of the process from 30-50 percent to 70-80 percent. This reduction in fuel requirements translates directly to reduced GHG emissions. In addition, there is often an additional GHG savings that results if fuel switching from coal to natural gas or biomass is included.

CHP is very widely used in the industrial sector already. There are nearly 1,800 active manufacturing, mining, construction, and agricultural CHP installations in the U.S. These facilities provide over 45 percent of the total annual industrial steam requirements. In commercial and institutional applications there are over 2,000 active CHP systems, which provide about 10 percent of the total boiler load used for space heating, water heating, and steam-driven chillers. Although many of the ICI applications with the largest thermal loads already have CHP systems, there is still room for additional conversions.

The most attractive ICI boiler candidates for CHP conversion are those that operate with a high annual operating factor, meeting a steady thermal load. Such systems maximize the potential efficiency benefits of CHP and provide a higher return on the required capital investment. For industrial applications, process industries with 2 and 3 shift operation represent a good target. In the commercial and institutional sector, facilities that have continuous thermal demand such as hospitals, college campuses, hotels, military bases, and prisons represent the best targets. Lower load factor applications with high thermal utilization will also show efficiency and GHG benefits, but the economic return on the investment needed to convert to CHP will be lower. In some cases, particularly in process industries, a CHP facility sized to the thermal load will produce more power than can be utilized on-site. This excess power can often be sold into the wholesale power market.

For a site with the appropriate thermal loads, there are a number of technical alternatives for converting to CHP:

- In rare cases, CHP could be added to an existing ICI boiler by increasing the steam pressure, adding a super-heater, and utilizing a back pressure steam turbine to generate power from the high pressure steam and then delivering lower pressure steam to the process. Most ICI boilers are not designed to be operated at higher pressures than those at which they are currently being operated, so this option will, in most cases, not be available.

- A steam turbine CHP system generally requires a complete boiler replacement to provide the necessary steam conditions for power generation through a back-pressure or extraction steam turbine generator. The electric to thermal (E/T) output ratio for this type of CHP system ranges from 0.05 to 0.15, that is, 5 to 15 percent of the energy output from this type of system is in the form of electricity and the remaining 85-95 percent is steam. This type of system is commonly used when there is a solid fuel source such as coal, biomass, or waste.

- For more power generation, a combustion turbine with heat recovery steam generator (HRSG) can be used for the CHP system with the existing boiler providing back-up steam when the CHP system is not operating. This type of system has an E/T ratio of 0.45-1.05 with the higher E/T ratios coming from larger turbines with higher electric generating efficiencies. Additional steam can be generated from this type of system through the use of duct burners in the HRSG. This additional steam is generated very efficiently (87-90 percent higher heating value) because the turbine exhaust which provides the combustion air is effectively preheated to a fairly high level. This type of system is typically used where electric and thermal demands are high (greater than 3 MW of electricity and 10-20 MMBtu/hr of steam) and either natural gas or distillate oil is already used for the existing boiler or fuel switching to a gas CHP system makes economic sense.

- Systems using large gas turbines can increase the E/T ratio by increasing the pressure of the steam produced by the HRSG and adding a back-pressure steam turbine for additional power production. These combined cycle systems typically produce over 100 MW of electric power with an E/T ratio of around 1.0 to 2.0 or more. This configuration is often used for large electric generators that are sited to produce power for sale to the grid with steam sales to a nearby industrial plant.

- Smaller ICI boilers, less than 1-2 MMBtu/hr, can be replaced by a variety of gas-fired CHP systems with heat recovery producing hot water or low pressure steam for the thermal loads. Reciprocating engines, microturbines, and fuel cells are all used for this purpose. These systems are particularly well suited for the sizes and loads of commercial and institutional buildings.

In addition, to the physical matching of a CHP system to the facility electric and thermal loads, CHP systems require a fairly substantial investment ($1,000-2,500/kW). This investment will have an economic return where ratio of electric to gas prices, also called the spark spread, is around 3 or higher. Larger industrial systems can be economic at somewhat lower spark spreads; very small systems often need a somewhat higher spark spread.

Another important factor that affects the technology selection is the ratio of heat to electricity demand at the site. The most efficient sizing approach for CHP is to size the system to meet the base thermal load. This can, at times, mean the CHP system will produce more power than can be used on-site. However, with deregulation of the electricity market in the US, it is often possible for industrial facilities to sell the excess electricity to the grid; this provides more flexibility in the design of CHP facilities, even though economics would dictate the final design configuration.

The economic and technical factors that would make CHP conversion of ICI boilers attractive can be summarized as follows:

- High annual operating hours
- Thermal demand with high annual load factor
- Coincident high load factor electric demand on-site or an economic electricity export market that the CHP system can access
- Spark spread (ratio of electric to fuel prices) of around 3 or higher
- Power quality and reliability issues at the site that the CHP system can help to address
- Economies of scale – the larger the electric and thermal requirements, the more economic CHP will be for any given spark spread, though small systems have also been installed effectively in high electric cost markets.

As previously described, CHP systems have already achieved significant market penetration in industrial applications and somewhat more modest success in commercial and institutional markets. There are about 4,000 operating CHP facilities providing over 84 GigaWatts of electric capacity and 1.7 quads of thermal energy (ICF 2010) .

GHG emissions reductions due to CHP conversion depend on the before and after energy configuration, but the benefits can be quite substantial.

An industrial, commercial, or institutional facility with an E/T ratio of 0.7, separately purchasing electricity generated at 33 percent efficiency and producing steam in an ICI boiler at 80 percent efficiency results in a combined efficiency of 50 percent. A gas turbine CHP system with an electrical generating efficiency of 30 percent and an E/T ratio of 0.7 can meet the same electric and thermal loads with an overall efficiency of 72 percent. This improvement represents a 30 percent reduction in overall fuel use. The level of overall CO_2 reductions is a function of the CO_2 intensity of the displaced central station power production and the fuels used at the site.

If the conversion also includes fuel switching (e.g., from coal or oil to natural gas), additional CO_2 emission reduction could be achieved. A CHP Emission Calculator developed by the US DOE and EPA could be useful in estimating emissions from CHP plants (EEA, 2004)

Disadvantages of CHP conversation of ICI boilers include:

- The most important barrier is the required investment, which is usually substantial. The thermal and electric benefits, where feasible, however, show the long-term gains in installing CHP weigh favorably against other control options.

- If there is excess electricity from the CHP facility, while regulatory changes have made it easier to sell it to the electric utilities or industrial customers, the selling requires time to negotiate contracts and is often perceived as a nuisance by many industrial companies. For example, connecting a CHP to the electrical grid involves compliance with national codes and consensus standards issued by the National Fire Protection Association and include the National Electric Code, the Occupational Safety and Health Administration, and local and state regulatory authorities. Also, electric utilities have their own interconnection and safety requirements, which can add to the complexity of the project.

- If a facility chooses to sell excess electricity, utilities often require written agreements concerning rates, metering, insurance and liability, standby power, operating schedules, and other operational issues.

- The design modifications require shut-down of the plant for a few weeks or months; such interruption is very difficult for industrial facilities to accommodate.

- Reliability may also be a barrier in accepting new technologies (e.g., fuel cells) which are more efficient, but may be perceived to be less reliable than the conventional proven technologies.

- Site permitting for CHP systems will be required to be taken into consideration. As with other combustion devices, construction and operating permits would need to be obtained to comply with applicable environmental regulations including the non-attainment New Source Review program requirements or the PSD permitting process, depending on the air quality where the facility is located. Because current air quality regulations do not recognize the overall energy efficiency of CHP or credit the emissions avoided from displaced grid electricity generation, project planning is generally required to include designs for emission control systems that achieve Lowest Achievable Emission Rate compliance or represent BACT. However, where output-based standards are available, they can be employed to show CHP's dual thermal and electrical outputs. In addition, emissions testing and monitoring equipment for verifying compliance are required to be included as part of the design. The cost of emission control equipment, as well as the cost of applying for construction and operating permits, can be significant. This is especially so for smaller CHP systems where the incremental cost is often disproportionately high.

- Lack of space (e.g., for new equipment and fuel storage) and/or lack of natural gas on site (in those cases where gas is not already available on site) may be a site-specific barrier.

EPA Contacts

Jim Eddinger
U.S. EPA
OAQPS/SPPD/ESG
Mail Code D243-01
Research Triangle Park, NC 27711
Phone: 919-541-5426
Fax: 919-541-5450
eddinger.jim@epa.gov

Christian Fellner
U.S. EPA
OAQPS/SPPD/ESG
Mail Code D243-01
Research Triangle Park, NC 27711
Phone: 919-541-4003
Fax: 919-541-5450
fellner.christian@epa.gov

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