Diane B. McCreevey
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Editors

REDUCING GREENHOUSE GAS EMISSIONS

Available and Emerging Technologies

Environmental Science, Engineering and Technology

NOVA

ENVIRONMENTAL SCIENCE, ENGINEERING AND TECHNOLOGY

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PREFACE

This book examines control techniques and measures to mitigate greenhouse gas (GHG) emissions from specific industrial sectors such as coal-fired electric generating units; the petroleum industry and the iron and steel industry.

Chapter 1- 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.

Chapter 2- 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.

Chapter 3- 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.

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Chapter 1

AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS*

United States Environmental Protection Agency

ACRONYMS AND ABBREVIATIONS

APFBC	Advanced pressurized fluidized bed combustion
ASTM	American Society for Testing and Materials
ASME	American Society of Mechanical Engineers
ASU	Air separation unit
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CCS	Carbon capture and storage
CEMS	Continuous emission monitoring system
CFB	Circulating fluidized bed
CH4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
EGU	Electric generating unit
EPA	U.S. Environmental Protection Agency
FBC	Fluidized bed combustion
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
GHG	Greenhouse gas
H2O	Water

* This is an edited, reformatted and augmented version of the United States Environmental Protection Agency publication, dated October 2010.

HRSG	Heat recovery steam generator
HHV	Higher heating value
IGCC	Integrated gasification combined cycle
IEA	International Energy Agency
kJ	Kilojoule
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
Mg	Megagram
MMBtu/hr	Million Btu per hour
MPa	Megapascal
MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt-hour
MSW	Municipal solid waste
N2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NOX	Nitrogen oxides
O&M	Operation and maintenance
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PM	Particulate matter
PRB	Power River Basin
scfm	Standard cubic feet per minute
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SNCR	Selective noncatalytic reduction
ton/day	tons per day
ton/yr	tons per year
U.S. DOE	U.S. Department of Energy
U.S. EIA	U.S. Energy Information Administration

1. 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.

This document provides information on control techniques and measures that are available to mitigate GHG emissions from the coal-fired electric generating sector at this time. The primary GHG emitted by the coal-fired electric generation industry is carbon dioxide (CO_2), and the control technologies and measures presented in this document focus on this pollutant. 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.

1.1. Electric Power Generation Using Coal

Electricity is generated at most electric power plants by using mechanical energy to rotate the shaft of electromechanical generators. The mechanical energy needed to rotate the generator shaft can be produced from the conversion of chemical energy by burning fuels or from nuclear fission; from the conversion of kinetic energy from flowing water, wind, or tides; or from the conversion of thermal energy from geothermal wells or concentrated solar energy. Electricity also can be produced directly from sunlight using photovoltaic cells or by using a fuel cell to electrochemically convert chemical energy into an electric current.

In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (coal, natural gas, petroleum liquids) (U.S. EIA 2010). The combustion of a fossil fuel to generate electricity can be either: 1) in a steam generating unit (also referred to simply as a "boiler") to feed a steam turbine that, in turn, spins an electric generator: or 2) in a combustion turbine or a reciprocating internal combustion engine that directly drives the generator. Some modern power plants use a "combined cycle" electric power generation process, in which a gaseous or liquid fuel is burned in a combustion turbine that both drives electrical generators and provides heat to produce steam in a heat recovery steam generator (HRSG). The steam produced by the HRSG is then fed to a steam turbine that drives a second electric generator. The combination of using the energy released by burning a fuel to drive both a combustion turbine generator set and a stream turbine generator significantly increases the overall efficiency of the electric power generation process.

Coal is the most abundant fossil fuel in the United States and is predominately used for electric power generation. In 2008, approximately 49% of the net electricity generated in the U.S. was produced by coal (U.S. EIA 2010). Historically, electric utilities have burned solid coal in steam generating units. However, coal can also be first gasified and then burned as a gaseous fuel. The integration of coal gasification technologies with the combined cycle electric generation process is called an integrated gasification combined cycle (IGCC) system or a "coal gasification facility". For the remainder of this document, the term "electric generating unit" or "EGU" is used to mean a solid fuel-fired steam generating unit that serves a generator that produces electricity for sale to the electric grid.

2. Coal-Fired Electric Generating Units

This section provides a summary overview of the types or ranks of coal that are typically burned in EGUs operating in the United States, the most commonly used combustion processes, and the resulting emissions of greenhouse gases.

2.1. Coals Burned in U.S. EGUs

In the United States, coals are ranked based on the degree of metamorphism (effectively, the geological age of the coal and the conditions under which the coal formed). These classification criteria have been standardized by the American Society for Testing and Materials (ASTM) method D-388. Under the ASTM method, coals are divided into four major categories called "ranks:" anthracite, bituminous coal, subbituminous coal, and lignite. Typical coal characteristics for the three most commonly used coal ranks are summarized in Exhibit 2-1.

Exhibit 2-1. Selected characteristics of major coal ranks used for electricity generation in the United States

Coal Rank[a]	Higher Heating Value (HHV) Range Defined by ASTM D-388	Typical Coal Moisture Content[b]	Coal Delivered for U.S. Electric Power Production in 2008[c,d]		
			Total Coal Quantity Delivered Nationwide (1,000 tons)	Average Ash Content	Average Sulfur Content
Bituminous	>10,500 Btu/lb	2 to 16%	463,943	10.6%	1.68%
Subbituminous	<10,500 Btu/lb and >8,300 Btu/lb	15 to 30%	522,228	5.8%	0.34%
Lignite	< 8,300 Btu/lb	25 to 40%	68,945	13.8%	0.86%

[a] Anthracite coal use is limited to reclaiming coal from coal refuse piles for use in a few power plants located close to the anthracite mines in eastern Pennsylvania.

[b] Reference: U.S. EPA, 2001.

[c] Reference: U.S. EIA, 2010, Table 3.6.

[d] Includes data collected from electric utilities, independent power producers, and combined heat and power producers.

Most coal-fired EGUs in the United States burn either bituminous or subbituminous coals. Approximately one half of the tonnage of coals delivered to U.S. electric power generation facilities was subbituminous (49.5%), and another 44% was bituminous coal. Some coal-fired EGUs burn multiple coal ranks. At many of these facilities, the coals are blended together before firing. However, some facilities may switch between coal ranks because of site-specific considerations. The largest sources of bituminous coals burned in EGUs are mines in regions along the Appalachian Mountains, in southern Illinois, and in Indiana. Additional bituminous coals are supplied from mines in Utah and Colorado. The vast majority of subbituminous coals are supplied from mines in Wyoming and Montana, and many EGUs burn subbituminous coals from the Powder River Basin (PRB) region in Wyoming. This material is often referred to simply as "PRB coal."

In general, the burning of lignite or anthracite by electric utilities is limited to those EGUs that are located near the mines supplying the coal. Lignite accounted for approximately 6.5% of the total tonnage of coal delivered to electric utility power plants in 2008. All of those facilities were located near the coal deposits from which the lignite was mined in Texas, Louisiana, Mississippi, Montana, or North Dakota. Similarly, anthracite use was limited to a few power plants located close to the anthracite mines in eastern Pennsylvania. The coal-fired EGUs at those facilities primarily burn anthracite that has been reclaimed from coal refuse piles of previous mining operations. In general, "coal refuse" means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 % (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis. Coal refuse piles from previous mining operations are primarily located in Pennsylvania and West Virginia. Current mining operations generate less coal refuse than older ones.

2.2. Coal Utilization in U.S. EGUs

Steam turbine power plants operate on the Rankine thermodynamic cycle. The steam is produced by the boiler, where water pumped into the boiler ("feedwater") passes through a series of tubes to capture heat released by coal combustion and then boils under high pressure to become superheated steam. The superheated steam leaving the boiler then enters the steam turbine throttle, where it powers the turbine and connected generator to make electricity.

After the steam expands through the turbine, it exits the back end of the turbine into the surface condenser, where it is cooled and condensed back to water. This condensate is then returned to the boiler through high-pressure feed pumps for reuse. Heat from the condensing steam is normally rejected to cooling water circulated through the condenser which then goes to a surface water body, such as a river, or to an on-site cooling tower.

An EGU can be classified as either dry or wet bottom, depending on the ash removal technique used. Dry bottom boilers fire coals with high ash fusion temperatures, allowing for solid ash removal. In the less common wet bottom (slag tap) boilers, coal with a low ash fusion temperature is fired, and molten ash is drained from the bottom of the boiler.

Coal-fired EGUs use one of five basic coal utilization processes.

- Stoker-fired
- Pulverized coal (PC)
- Cyclone-fired
- Fluidized-bed combustion (FBC)
- Coal gasification (IGCC)

To improve the overall thermal conversion efficiency of the Rankine cycle, the majority of EGUs include a series of heat recovery sections. These sections are located downstream from the furnace chamber and are used to extract additional heat from the flue gas. The first section contains a "superheater," which is used to increase the steam temperature. The second heat recovery section contains a "reheater," which reheats the steam exhausted from the first stage of the steam turbine. This steam is then returned for another pass thorough a second stage of the turbine. The reheater is followed by an "economizer," which preheats the condensed feedwater recycled back to the boiler tubes in the furnace. The final heat recovery section is the "air heater," which preheats the ambient air used for coal combustion. The flue gas exhausted from the boiler passes through particulate matter (PM) and other air emissions control equipment before being vented to the atmosphere through a stack.

2.2.1. Stoker-Fired Coal Combustion

First introduced to the electric utility industry in the late 1800s, stoker-fired coal combustion is the oldest boiler coal-firing design. In a stoker-fired boiler, the coal is crushed and burned on a grate. Heated air passes upward through openings in the grate. Stokers are classified according to the way coal is fed to the grate – as underfeed stokers, overfeed stokers, and spreader stokers (see Exhibit 2-2). Stoker firing coal combustion is an obsolete technology for new coal-fired EGUs because the other newer coal combustion technologies provide superior coal combustion efficiency, applicability, and other advantages. There are still a few small stoker-fired EGUs in service in the U.S., but as these units are retired no new coal-fired stoker-fired EGUs are expected to be built. The majority of new stoker-fired boiler capacity is expected to occur at municipal solid waste combustor facilities and facilities burning solid biomass.

2.2.2. Pulverized-Coal Combustion

Pulverizing coal into a very fine powder allows the coal to be burned more easily and efficiently. For a PC-fired EGU, the coal must first be pulverized in a mill to the consistency of talcum powder (i.e., at least 70% of the particles will pass through a 200-mesh sieve). The pulverized coal is generally entrained in primary combustion air before being blown through the burners into the combustion chamber where it is fired in suspension. PC-fired boilers are classified by the firing position of the burners either as wall-fired or tangential-fired (see Exhibit 2-2).

A PC-fired boiler consists of multiple sections, and Exhibit 2-3 presents a simplified schematic of the major components of a PC-fired boiler using subcritical steam conditions. The pulverized coal is ignited and burned in the section of the boiler called the "furnace chamber" (or sometimes the "firebox"). Ambient air blown into the furnace chamber provides the oxygen required for combustion. The walls of the furnace chamber are lined with vertical tubes containing the feedwater. Heat transfer from the hot combustion gases in the furnace boils the water in the tubes to produce the high-temperature, high-pressure steam. The steam is separated from boiler water in a steam drum and sent to the steam turbine. The remaining water in the drum re-enters the boiler for further conversion to steam. The hot combustion products are vented from the furnace in a gas stream called collectively flue gas.

Exhibit 2-2. Characteristics of coal-firing configurations used for U.S. EGUs

Coal-firing Configuration	Application to U.S. EGUs	Coal Combustion Process Description	Distinctive Design/Operating Characteristics	
Stoker-fired	• Oldest coal-firing design first introduced to the electric utility industry in the late 1800s. • Not a significant contributor to overall U.S. nationwide MW generating capacity. • New EGUs are not expected to use this coal-firing design because of the superior performance and advantages of newer coal combustion technologies.	Coal is crushed into large lumps and burned in a fuel bed on a moving, vibrating, or stationary grate. Coal is pushed, dropped, or thrown onto the grate by a mechanical device called a "stoker."	Spreader-stoker	A flipping mechanism throws the coal into the furnace above the grate. The fine coal particles burn in suspension while heavier coal lumps fall to the grate and burn in a fuel bed.
			Underfeed	Coal fed by pushing the coal up underneath the burning fuel bed.
			Traveling grate	Coal is fed by gravity onto a moving grate and leveled by a stationary bar at the furnace entrance.
Pulverized-Coal Combustion	• Coal-firing design predominately used at existing U.S. EGUs • In 2008, consumed ~ 92% of total coal consumed by U.S. EGUs.[a] • Currently coal-firing design of choice for new large coal-fired EGUs (> 400 MWe) built in U.S.	Coal is ground to a fine powder that is pneumatically fed to a burner where it is mixed with combustion air and then blown into the furnace. The pulverized- coal particles burn in suspension in the furnace. Unburned and partially burned coal particles are carried off with the flue	Wall-fired	An array of burners fire into the furnace horizontally, and can be positioned on one wall or opposing walls depending on the furnace design.
			Tangential-fired (Corner-fired)	Multiple burners are positioned in opposite corners of the furnace producing a fireball that moves in a cyclonic motion and expands to fill the furnace.
Cyclone	• Existing cyclone EGUs in U.S. constructed prior to 1981. • In 2008, consumed ~ 6% of total coal consumed by U.S. EGUs. • New EGUs are not expected to use this boiler type because of the commercial availability of FBC technology.	Coal is crushed into small pieces and fed through a burner into the cyclone furnace. A portion of the combustion air enters the burner tangentially creating a whirling motion to the incoming coal.	Designed to burn coals with low-ash fusion temperatures that are difficult to burn in PC boilers. The majority of the ash is retained in the form of a molten slag.	

Exhibit 2-2. (Continued)

Coal-firing Configuration	Application to U.S. EGUs	Coal Combustion Process Description	Distinctive Design/Operating Characteristics	
Fluidized-bed Combustion	• FBC EGUs increasingly being built in U.S. to burn low rank coals, coal refuse, and blends of coal with other solid fuels such as petroleum coke or biomass. • In 2008, consumed approximately 2% of total coal consumed by U.S. EGUs.a • Atmospheric FBC EGUs are currently operating in the U.S. with generating capacities in the range of 250 to 300 MWe. • No Pressurized FBC boilers currently used for U.S. EGUs	Coal is crushed into fine particles. The coal particles are suspended in a fluidized bed by upward-blowing jets of air. The result is a turbulent mixing of combustion air with the coal particles. Typically, the coal is mixed with a sorbent such as limestone (for SO_2 emission control). The unit can be designed for combustion within the bed to occur at atmospheric or elevated pressures. Operating temperatures for FBC are in the range of 1,500 to 1,650°F (800 to 900°C).	Bubbling fluidized bed (BFB)	Operates at relatively low gas stream velocities and with coarse-bed size particles. Air in excess of that required to fluidize the bed passes through the bed in the form of bubbles.
			Circulating fluidized bed (CFB)	Operates at higher gas stream velocities and with finer-bed size particles. No defined bed surface. Must use high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency.
Coal Gasification (e.g., IGCC)	• Limited application to EGUs to date. • Some new proposed EGU projects using coal gasification as part of IGCC plant.	Synthetic combustible gas ("syngas") derived from an on-site coal gasification process is burned in a combustion turbine. The hot exhaust gases from the combustion turbine pass through a heat recovery steam generator to produce steam for driving a steam turbine/generator unit.	Coal gasification units are unique from the other coal-firing configurations because a gaseous fuel (synfuel or syngas) is burned instead of solid coal and combines the Rankine and Brayton thermodynamic cycles as is the case for a combined cycle power plant.	

[a] Source: U.S. EIA, 2008.

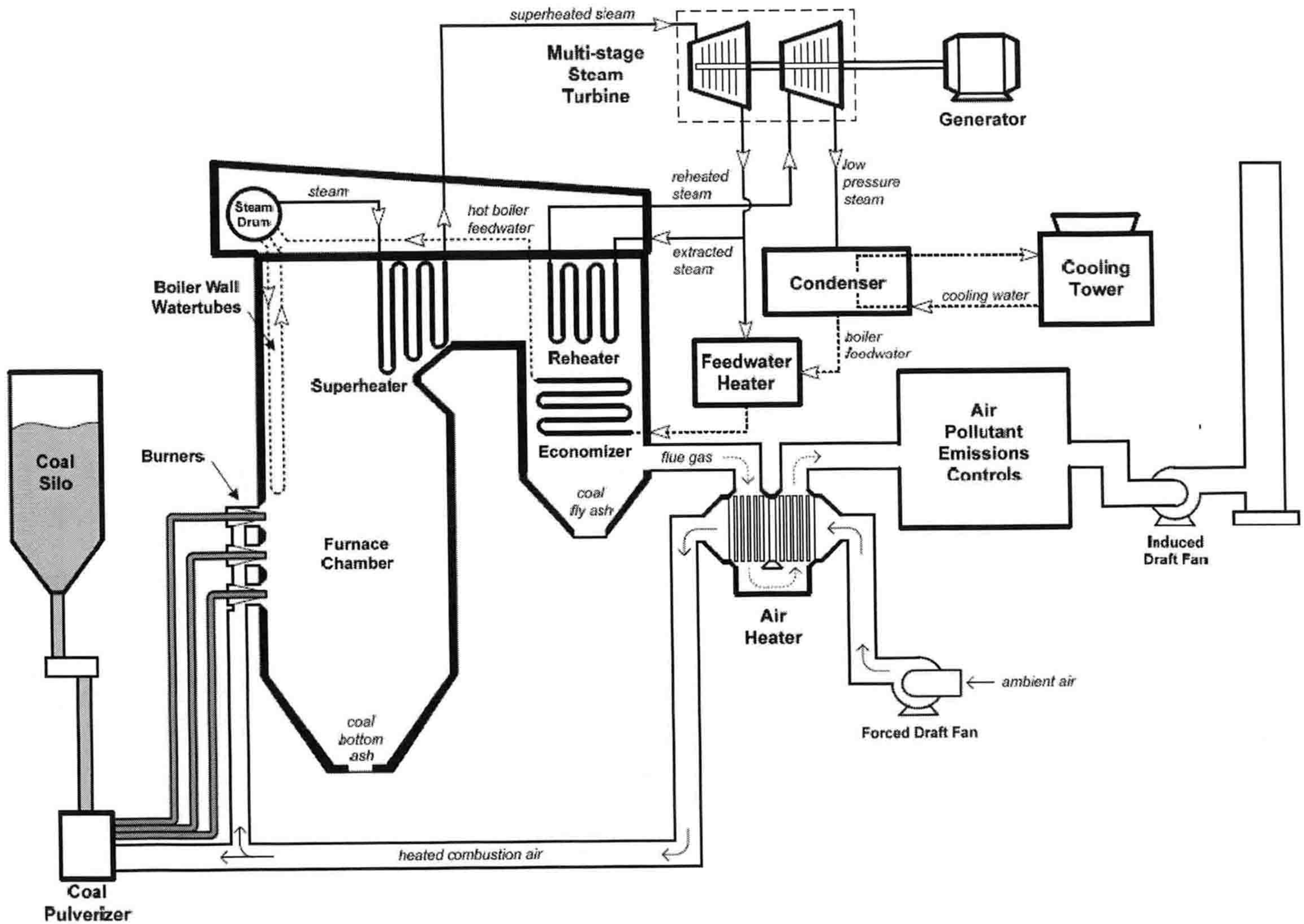

Exhibit 2-3. Simplified schematic of a PC-fired EGU using a subcritical boiler.

2.2.3. Cyclone Coal Combustion

Cyclone coal combustion technology was developed as an alternative to PC-firing because it requires less pre-processing of the coal and allows for the burning of lower rank coals with higher moisture and ash contents. Cyclone boilers use burner design and placement (i.e., several water-cooled horizontal burners) to produce high-temperature flames that circulate in a cyclonic pattern. The coal is crushed to a 4-mesh size, and then fed tangentially with primary air, to a horizontal cylindrical combustion chamber. In this chamber, small coal particles are burned in suspension, while the larger particles are forced against the outer wall. The high temperatures developed in the relatively small boiler volume, combined with the low fusion temperature of the coal ash, causes the ash to form a molten slag, which is drained from the bottom of the boiler through a slag tap opening. Existing cyclone EGUs in the U.S. were designed or installed before 1981. Cyclone EGUs have high nitrogen oxides (NOx) emission rates and no new cyclone boilers are expected to be built. Fluidized-bed combustion is an alternative technology that is able to burn lower rank coals without high NOx emissions.

2.2.4. Fluidized-Bed Combustion

The term "fluidized" refers to the state of the bed materials (fuel and inert material [or sorbent]) as gas passes through the bed. In a typical FBC EGU, combustion occurs when coal and a sorbent, such as limestone, are suspended through the action of primary combustion air distributed below the combustor floor. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like characteristic (i.e., fluidized). FBC can occur in either atmospheric or pressurized boilers. Two fluidized bed designs can be used for atmospheric and pressurized FBC boilers: a bubbling fluidized bed or a circulating fluidized bed (CFB) (see Exhibit 2-2). An advantage of CFB boiler EGUs compared to PC-fired EGUs is fuel flexibility. A CFB boiler EGU can burn any rank of coal (including coal refuse), petroleum coke (a carbonaceous solid derived from oil refinery coker units or other cracking processes), and biomass without significant modifications.

The combustion temperature of a FBC boiler (1,500 to 1,650°F) is significantly lower than a PC-fired boiler (2,450 to 2,750°F), which results in lower NOX formation and the ability to capture sulfur dioxide (SO_2) with limestone injection in the furnace. Even though the combustion temperature of a FBC boiler is low, the circulation of hot particles provides efficient heat transfer to the furnace walls and allows longer residence time for carbon combustion and limestone reaction. This results in good combustion efficiencies, comparable to PC-fired EGUs.

Atmospheric CFB boilers have successfully been scaled-up and are operating at a number of facilities throughout the world. Exhibit 2-4 presents a simplified schematic of the major components of a CFB boiler EGU. Calcium in the sorbent combines with SO_2 gas to form calcium sulfite and sulfate solids, and solids exit the combustion chamber and flow into a hot cyclone. The cyclone separates the solids from the gases, and the solids are recycled for combustor temperature control. Heat in the flue gas exiting the hot cyclone is recovered in a series of heat recovery sections of the boiler to produce steam. The superheated steam leaving the boiler then enters the steam turbine, which powers a generator to produce electricity. Like PC-fired EGUs, CFB boilers can be used with either subcritical or supercritical steam cycles.

Currently, the capacity of CFB subcritical boilers ranges from 25 to 350 MWe. Examples of these systems include (Foster Wheeler North America Corp., 2009):