

# APPLICATIONS OF OXYGEN FOR NO<sub>x</sub> CONTROL AND CO<sub>2</sub> CAPTURE IN COAL-FIRED POWER PLANTS

by

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*Two promising combustion modification approaches applicable to pulverized coal fired boilers are presented: "Oxygen-Enriched Combustion" (OEC) for NO<sub>x</sub> control and "Oxy-Combustion" (PC-OC) for CO<sub>2</sub> capture. Oxygen-enriched air rather than air is used as an oxidizer in the OEC technology. Unlike flue gas treatment technologies, OEC directly impacts the NO<sub>x</sub> formation process by significantly reducing the conversion of coal bound nitrogen to NO<sub>x</sub>. Pilot-scale and full-scale tests have shown 20 to 30% NO<sub>x</sub> reduction from an optimized staged-air baseline. In addition to the overall cost competitiveness and the reduced capital requirements, other significant advantages of the O<sub>2</sub>-enriched technology vs. existing low NO<sub>x</sub> technologies are presented.*

*The PC-OC technology is shown as a cost-effective technology for CO<sub>2</sub> capture from existing or new coal-fired power plants. Pure oxygen diluted in recycled flue gases is used as an oxidizer. The process has been successfully demonstrated and extensively characterized at pilot-scale level (1.5 MW). The tests have shown substantial benefits of the PC-OC technology, in terms of NO<sub>x</sub> reduction (60-70% from air-baseline), overall plant efficiency, etc. The cost effectiveness of this capture technology compared to competitive amine scrubbing technology was investigated. The cost of CO<sub>2</sub> avoided was around \$36/ton for the new PC-OC cases, about \$48/ton on a retrofit PC-OC case, which is about 25 to 40% cheaper than the amine scrubbing system. Those numbers were calculated for sub-critical units and include the cost of CO<sub>2</sub> compression up to 80 bar.*

Key words: *oxy-combustion, coal, oxygen, CO<sub>2</sub>, carbon capture, NO<sub>x</sub>, acid rain, green house effect*

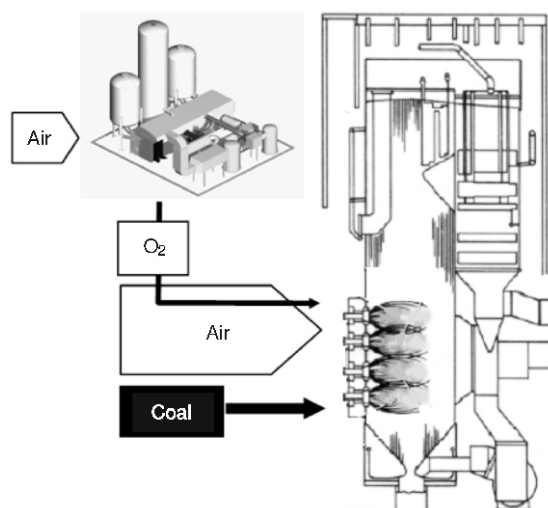
## Introduction

Coal provides 23% of worldwide primary energy needs, and generates about 38% of the world's electricity. It is the major fuel used for generating electricity, and countries heavily dependent on coal include Australia (77% of power originates from coal), China (78%), India (70%), U. S. A (56%), South Africa (78%) and some European countries (52% in Germany, 96% in Poland, 72% in Czech Republic, 67% in Greece,

etc.). Coal will continue to be a prime fuel for electric power generation, and the coal-fired plants will have to operate well into the future. However, in many countries the plants are being subjected to more stringent environmental regulations that restrict the quantity of pollutant that can be emitted into the atmosphere.

### ***Oxygen-enriched combustion (OEC) for NO<sub>x</sub> control***

Mitigation of nitrogen oxides (NO<sub>x</sub>) emissions is one of the most immediate areas of concern for the coal-fired electricity production sector. The present and future NO<sub>x</sub> emission limits and compliance programs set up by various governments have created the impetus for industrial implementation of competitive NO<sub>x</sub> reduction technologies.



**Figure 1. Oxygen-enrichment in coal-fired power plants for NO<sub>x</sub> emission reduction (schematic)**

Bringing the existing coal-fired power plants into compliance with the tighter NO<sub>x</sub> emission regulations will require new technological advancements to replace or enhance the performance of existing technologies.

OEC represents a breakthrough technology for NO<sub>x</sub> control. A small quantity of the combustion air is replaced by a stoichiometric equivalent of pure oxygen. As schematically shown in fig. 1, air is still the main oxidizer, since less than 10% of the overall combustion air is replaced by pure oxygen.

The detailed description of the technology along with experimental results are presented.

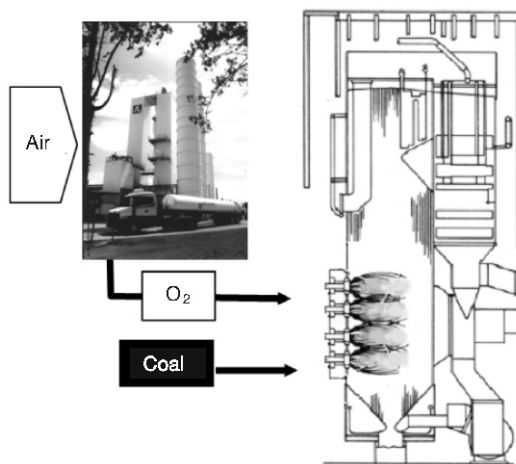
### ***Oxy-combustion in pulverized coal boilers (PC-OC) for CO<sub>2</sub> capture***

Fossil fuel combustion is the major contributor of increased greenhouse gas (GHG) emissions. As coal-fired power plants are the largest single point emitters of GHG, there is a compelling need to deploy new and retrofit technologies to capture and sequester the CO<sub>2</sub>. Numerous programs are being carried out promoting clean coal technologies. Capture cost represents around 75% of the total cost for the capture, transportation and se-

questration of CO<sub>2</sub> [1]. The flue gas exiting a conventional air/coal power plant contains only 10% to 15% CO<sub>2</sub> by volume. The balance is mostly made of nitrogen. Such low CO<sub>2</sub> content results in high capture cost while scrubbing the flue gases with amine-type absorbents.

Cost-effective capture of the CO<sub>2</sub> resulting from the combustion can be achieved by separating the N<sub>2</sub> from the O<sub>2</sub> in the air prior to combustion (fig. 2). O<sub>2</sub> is usually diluted in recycled flue gases for temperature control. In this paper, combustion of pulverized coal (PC) in oxygen-enriched flue gases is referred to as oxy-combustion, or PC-OC.

The PC-OC process has been investigated in partnership with the US Department of Energy. Experimental results obtained from a pilot-scale pulverized coal fired boiler simulator are provided. Techno-economic comparisons of the PC-OC technology *vs.* the amine scrubbing technology (Monoethanolamine or MEA) are also presented. Both retrofit and new plant cases are considered in the economic assessment.



**Figure 2. Oxy-combustion in coal-fired power plants for CO<sub>2</sub> capture (schematic)**

## Oxygen-enrichment for NO<sub>x</sub> control

### *NO<sub>x</sub> formation mechanism in pulverized coal fired boilers*

NO<sub>x</sub> generally refers to nitrogen monoxide NO and nitrogen dioxide NO<sub>2</sub>. Both are major contributors to acid rain and smog (ground level ozone) issues. The NO<sub>x</sub> partition in the flue gases of pulverized coal boilers is typically more than 95% NO and the remainder NO<sub>2</sub> [2]. During coal-combustion, the NO<sub>x</sub> production originates from three different mechanisms:

- fuel-NO<sub>x</sub> mechanism,
- thermal-NO<sub>x</sub> mechanism, and
- prompt-NO<sub>x</sub> mechanism.

In pulverized coal boilers, 70 to 80% of NO<sub>x</sub> is formed from the fuel-bound nitrogen species (fuel-N) via the fuel-NO<sub>x</sub> mechanism, and the remaining NO<sub>x</sub> is formed from atmospheric nitrogen (N<sub>2</sub>), via the thermal-NO<sub>x</sub> mechanism (5-25%), and via the prompt-NO<sub>x</sub> mechanism (less than 5%) [3]. Understanding and limiting the NO<sub>x</sub> formation in pulverized coal combustion is therefore strongly related to the fuel-N conversion mechanism. A complex series of reactions explains the transformation of organically

bound fuel-nitrogen into  $\text{NO}_x$  or  $\text{N}_2$ , including more than 50 intermediate species and hundreds of reactions.

The two main parameters affecting the fuel- $\text{NO}_x$  formation process are the volatile matter content of the fuel and the stoichiometry (air/fuel ratio). Coal nitrogen content (bound nitrogen only), also strongly impacts  $\text{NO}_x$  emission levels. Coal typically contains 0.5 to 3% nitrogen by weight on a dry basis. For comparison, natural gas also contains some nitrogen (0.5 to 20%); however it is molecular nitrogen  $\text{N}_2$ , and thus is not affected by the fuel- $\text{NO}_x$  mechanism.

Figure 3 summarizes the main reactions affecting fuel-nitrogen in the combustion process [4].

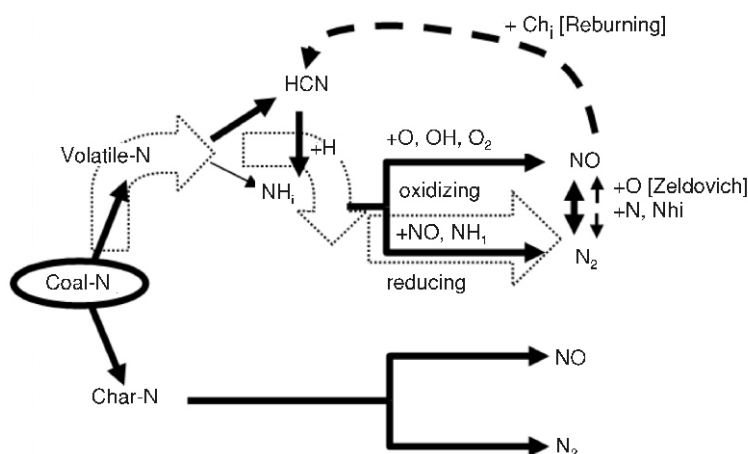


Figure 3. Fuel- $\text{NO}_x$  formation mechanism (simplified)

Four main steps can be identified:

- (1) **Devolatilization** releasing coal nitrogen compounds (coal-N) in a gaseous phase (Volatile-N), mainly as HCN, some as  $\text{NH}_3$ . The remaining coal-nitrogen compounds stay in the solid phase (char), and are referred to as char-N,
- (2) **HCN evolution to  $\text{NH}_3$**  species,
- (3)  **$\text{NH}_3$  oxidation to NO or reduction to  $\text{N}_2$**  depending on local conditions, and
- (4) **Reburning**, as some NO is recirculated back to the hot reducing zone of the flame and converted back to  $\text{N}_2$  while contacting  $\text{CH}_i$  radicals.

Both volatile-N and char-N can be evolved as NO or as  $\text{N}_2$ . Fuel- $\text{NO}_x$  formation is minimized by implementing specific conditions leading to  $\text{N}_2$  rather than NO [5-7]. For a given coal and particle size, three main conditions will independently or in combination promote fuel-bound nitrogen conversion into molecular nitrogen  $\text{N}_2$  rather than NO:

**fuel rich** (reducing) **conditions** at the burner level: by arranging fuel-rich “zones” in the furnace during the devolatilization stage, the nitrogen species in gas phase (volatiles) are more likely to be reduced to molecular nitrogen (N<sub>2</sub>) rather than oxidized to NO,

**high temperature** in the early stages of combustion increases the volatiles yield. As volatiles burn close to the burner exit, controlling the volatile-N (gas) to N<sub>2</sub> conversion is much easier than the char-N (solid) to N<sub>2</sub> conversion. High temperature at the burner exit also increases both the reburning rate of recirculated NO and the conversion rate of volatile-N into N<sub>2</sub> [8, 9], and

**long residence times** in the high temperature and reducing zones in the boiler lead to higher fuel-N to N<sub>2</sub> and NO to N<sub>2</sub> conversion.

Moore and Ellison [10] listed some examples of recent developments of NO<sub>x</sub> control technologies based on the principle of fuel-rich conditions and high temperature. They also highlighted the limitations that those technologies are facing today.

#### ***Available NO<sub>x</sub> control technologies for pulverized coal-fired utility boilers***

NO<sub>x</sub> reduction technologies available in the market today can be grouped into two broad categories: **combustion modifications** and **post-combustion** processes [3, 5, 11].

The most common combustion modification technologies include low-NO<sub>x</sub> burners (LNB), overfire air (OFA) and reburning. These technologies are based on air or fuel staging principles and have primarily been developed to limit fuel-NO<sub>x</sub> formation, as the main source of NO<sub>x</sub> in pulverized coal combustion.

Two main post-combustion technologies have been developed to enable further NO<sub>x</sub> abatement when combustion modifications alone are not sufficient to meet local regulations: Selective catalytic reduction (SCR) and Selective non-catalytic reduction (SNCR). A reducing agent (ammonia NH<sub>3</sub> or urea) is injected into the furnace or in the flue gases to react with NO and form N<sub>2</sub>. Careful design and operation, such as controlling the reagent dosage and assuring good mixing, are necessary to keep NH<sub>3</sub>/urea emissions low.

Other technologies referred to as hybrid processes or operational modifications use combinations of the above combustion and post-combustion solutions for retrofitting boilers.

#### ***Why another low-NO<sub>x</sub> technology?***

The previously listed combustion modifications for NO<sub>x</sub> reduction come with some limitations:

- **Overfire air (OFA)** techniques generally have three limitations. While diverting some air from the burner to the overfire air ports, the potential temperature reduction at the burner level may slow down the devolatilization process and reduce the

maximum achievable volatiles yield, which limits the potential fuel-N to  $N_2$  conversion. In addition, the burner stoichiometry can usually not be decreased below 0.8 due to flame stability concerns. Finally, the potential lower flame temperature and shorter fuel residence time of the OFA technology reduce the combustion efficiency, leading to increased fuel consumption and higher carbon content in the ash.

- **Low  $NO_x$  burners (LNB)** have been widely applied. However, their effectiveness is limited. Further, deep staging beyond the burner throat stoichiometry of 0.85-0.9 becomes indeed difficult to manage while maintaining the flame length, keeping the boiler turn-down ratio, maintaining acceptable carbon burn-out, enabling some coal type flexibility, and taking care of other combustion issues.

In most coal-fired plants, the  $NO_x$  levels achieved through installation of low- $NO_x$  burners and other combustion modification technologies are in the range of 0.3 to 0.5 lb per million Btu for high volatile bituminous coals. The emission limit imposed by the stricter regulations is 0.15 lb per million Btu.

As shown in tab. 1, the only commercial  $NO_x$  control technology currently capable of achieving the required reduction in pollutant removal is SCR.

**Table 1. Basic performances of  $NO_x$  emissions control technologies [3]**

Retrofit technology on coal-fired boiler	Typical $NO_x$ reduction rate
Overfire air (OFA)	10-30%
Low- $NO_x$ burners (LNB)	30-50%
Reburning + overfire air	40-50%
Selective non-catalytic reduction (SNCR)	20-30%
Selective catalytic reduction (SCR)	70-90%

SCR can remove approximately 80 to 90% of the  $NO_x$ , compared with 30 to 50% maximum for available combustion modifications. While SCR is considered the leading low- $NO_x$  option, it can also be an expensive technology depending upon the difficulty of the retrofit, the boiler generating capacity, and the remaining life of the power plant. In general, the coal power industry, especially smaller units, can benefit from other alternatives. Innovative low- $NO_x$  technologies that are more efficient than current combustion modification options (LNB, OFA...) are required for coal-fired power plants to address new regulations.

#### **Description of the OEC technology**

Both the conversion of devolatilized  $NH_i$  species into molecular nitrogen  $N_2$  and the reburning of recirculated NO require fuel-rich conditions and are significantly increased by flame zone high temperature. As mentioned in the previous section, fuel rich

conditions are obtained by staging the flame, but usually result in a reduced temperature at the burner level. To overcome this limitation, replacing some of the local burner air by oxygen-enriched air enables to increase, or at least maintain, the burner zone temperature while staging the air.

The technology developed by Air Liquide (AL) and The Babcock&Wilcox Company (B&W) targets the existing coal-fired boilers that need a safe, easy to implement and cost-effective retrofit solution to meet the new NO<sub>x</sub> regulations. The technology consists of injection of oxygen-enriched air in an existing coal-fired boiler to promote the conversion of fuel-bound nitrogen into molecular nitrogen and to limit its conversion into NO<sub>x</sub>. It requires the installation of proprietary oxygen injection equipment. Air remains the main oxidizer in the retrofitted boiler, with more than 90% of the oxygen molecules needed for complete coal burnout being provided by ordinary combustion air. Less than 10% of the stoichiometry, or less than 10% of the total oxygen molecules, is provided by pure oxygen.

Table 2 illustrates the OEC concept based on a 100 MW<sub>e</sub> air-blown coal boiler retrofitted with the oxygen-enriched low-NO<sub>x</sub> technology. The calculations have been made on a sub bituminous coal (US Powder River Basin – PRB coal) assuming 33% plant efficiency.

**Table 2. Overall input and output streams characteristics in coal-fired boilers while operated in air-blown conditions and in oxygen-enriched conditions**

	Air-blown PC boiler	OEC retrofitted PC boiler	
<b>Oxygen-enrichment level</b> (% of the overall stoichiometry provided by pure O <sub>2</sub> )	<b>0%</b>	<b>5%</b>	<b>10%</b>
Oxidizer	Air	O <sub>2</sub> -enriched air	O <sub>2</sub> -enriched air
<b>Air input</b>	<b>9,934 TPD (0%)</b>	<b>9,357 TPD ( 6%)</b>	<b>8,788 TPD ( 12%)</b>
Air removed		577 TPD	1,146 TPD
<b>Pure oxygen input</b>		<b>115 TPD</b>	<b>227 TPD</b>
Average oxidizer composition	<b>O<sub>2</sub> 21%</b> N <sub>2</sub> 79%	<b>O<sub>2</sub> 22%</b> N <sub>2</sub> 78%	<b>O<sub>2</sub> 23%</b> N <sub>2</sub> 77%
Flue gas output	11,108 TPD (0%)	10,645 TPD ( 4%)	10,189 TPD ( 8%)
Overall stoichiometric ratio (3% O <sub>2</sub> in flue gases, dry basis, by volume)	1.17	1.16	1.15
Flue gas composition (dry basis, by volume)	O <sub>2</sub> 3% CO <sub>2</sub> 16% N <sub>2</sub> 81%	O <sub>2</sub> 3% CO <sub>2</sub> 17% N <sub>2</sub> 80%	O <sub>2</sub> 3% CO <sub>2</sub> 18% N <sub>2</sub> 79%

TPD – metric tons per day



Providing 5% of the stoichiometry with pure oxygen while keeping 3% oxygen content in the flue gases consists of replacing 577 tons per day of the combustion air by 115 tons per day of pure oxygen. The oxygen content in the oxidizer stream would increase from 21% in air-combustion to an average of 22% in oxygen-enriched combustion.

With such a small increase in oxidizer  $O_2$  concentration, the implementation of the oxygen-enrichment does not require any modification to the equipment and materials of the boiler.

In addition to  $NO_x$  reduction, the OEC technology provides benefits such as:

- improvement in flame stability and flame attachment, enabling lower burner stoichiometry (higher staging) than in air-fired conditions, thus further reduction of the  $NO_x$  formation,
- shorter flames that enable application to smaller boilers at reduced burner stoichiometry,
- potential capacity increase for flue gas limited systems, and
- higher combustion efficiency and reduced unburned carbon in the fly ash.

Although oxygen-enrichment looks like a new concept in the utility industry, its development will benefit from a wide range of successful applications of oxygen in industrial combustion processes. Technologies based on oxygen-enrichment have significantly reduced emissions and increased efficiency in a variety of industrial combustion applications, such as glass melting and forming, cement/lime kilns, steel reheating furnaces, *etc.*

### ***OEC experimental results***

Oxygen-enrichment tests have been performed on B&W's 1.5 MW<sub>t</sub> (5 million Btu/hr) pilot-boiler simulator firing a subbituminous coal, and on B&W's 30 MW<sub>t</sub> (100 million Btu/hr) boiler firing a high volatile bituminous coal. A scaled version of B&W DRB-4Z® low- $NO_x$  burner has been used. A fraction of the combustion air has been replaced by pure oxygen; a variety of proprietary oxygen introduction arrangements have been tested; the burner stoichiometric ratio (BSR) has been varied from 0.9-0.95 (conventional BSR in air-fired conditions) down to the minimum level achievable while keeping good flame characteristics (stability, soot formation, *etc.*). The following sections summarize the results obtained on the 1.5 MW<sub>t</sub> boiler, referred to Small boiler simulator (SBS). The 30 MW<sub>t</sub> test results will be reported in a future paper.

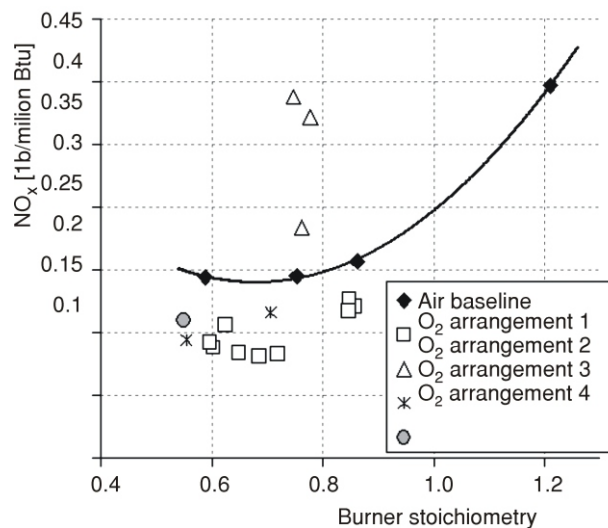
Note:  $NO_x$  emission levels have been measured in ppm in the dry flue gases and converted in pounds per million Btu (lb per million Btu). In air-fired conditions and for an average coal, 0.1 lb/million Btu equals about 123 mg/m<sup>3</sup>. Such conversion factor would be modified in oxygen-enriched combustion and oxy-combustion due to reduction of flue gas volume for a same coal input.



### *Impact of the oxygen introduction arrangement (O<sub>2</sub> arrangement)*

Oxygen introduction arrangement (O<sub>2</sub> AR) refers to the equipment used for injecting the oxygen or oxygen-enriched air into the combustion zone. For confidentiality reasons, the equipment geometries are not described in this paper.

Figure 4 shows the NO<sub>x</sub> emissions in lb per million Btu obtained while firing PRB coal and using four types of O<sub>2</sub> arrangement at various BSR. The results highlight that the selection of the oxygen injection arrangement is a key factor for a successful application of the OEC.



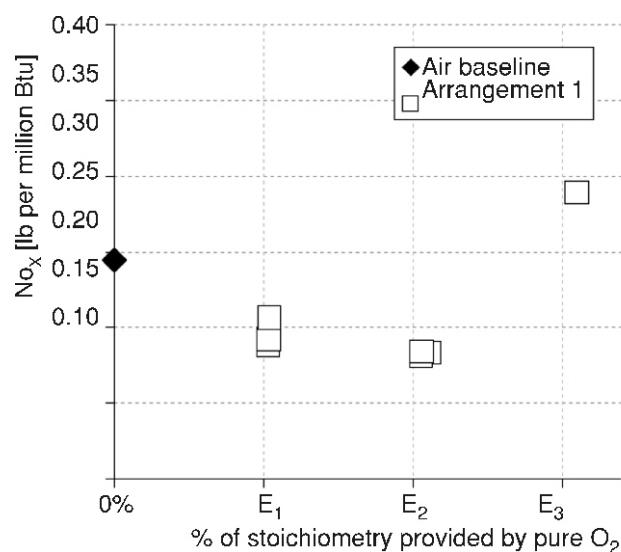
**Figure 4. NO<sub>x</sub> emission versus BSR-less than 10% of the stoichiometry is provided by pure O<sub>2</sub>**

While NO<sub>x</sub> levels were reduced by 28% from 0.25 (baseline) to 0.18 lb per million Btu (using O<sub>2</sub> AR1). The use of AR2 increased the NO<sub>x</sub> production by 13% to 50%. Oxygen enrichment using AR3 and AR4 also produced very stable flames at burner stoichiometry as low as 0.55, and a nominal NO<sub>x</sub> reduction of approximately 20% was observed.

Note that the baseline NO<sub>x</sub> achieved in the SBS was higher than B&W's commercial results. Based on several large-scale installations of DRB-4Z<sup>®</sup> low-NO<sub>x</sub> burners on boilers firing PRB coal, NO<sub>x</sub> emission levels of 0.16 to 0.2 lb per million Btu have been achieved.

*Impact of the oxygen enrichment level*

Figure 5 shows the  $\text{NO}_x$  emission in lb per million Btu using Arrangement 1, measured for three different oxygen enrichment levels referred to as  $E_1$ ,  $E_2$ , and  $E_3$ .



**Figure 5.  $\text{NO}_x$  emission versus  $\text{O}_2$ -enrichment level at burner stoichiometric ratio around 0.7**

Both enrichments  $E_1$  and  $E_2$  using  $\text{O}_2$  AR1 led to  $\text{NO}_x$  reduction when compared to the air-fired baseline. From 0.25 lb per million Btu for the air-fired baseline, the  $\text{NO}_x$  was reduced to 0.19 lb per million Btu (24%  $\text{NO}_x$  reduction) with  $E_1$  and to 0.18 lb per million Btu (28%  $\text{NO}_x$  reduction) with  $E_2$ . With enrichment  $E_3$ ,  $\text{NO}_x$  emissions increased by 15%.

Such results show that the oxygen enrichment level and oxygen introduction arrangement can be optimized on a site specific basis.

**Oxy-combustion for  $\text{CO}_2$  capture**

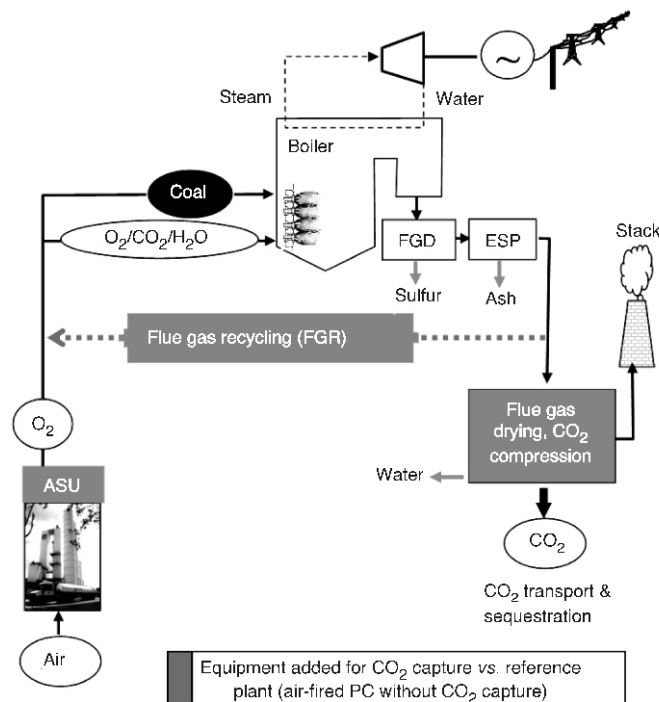
In partnership with the US Department of Energy's National Energy Technology Laboratory, Air Liquide has teamed with B&W and the Illinois State Geological Survey (ISGS) to develop and optimize the coal oxy-combustion process. The main objectives of this project are:

- (1) demonstrate the feasibility and measure the performances of the PC-OC technology with flue gas recycle on a pilot-scale coal-fired boiler, and
- (2) perform an techno-economic study, comparing combustion modifications via the PC-OC approach with alternate CO<sub>2</sub> capture technologies such as amine scrubbing.

### ***Description of the oxy-combustion process***

The PC-OC process is schematically illustrated in fig. 6.

In the oxy-combustion process, N<sub>2</sub> is separated from O<sub>2</sub> prior to the combustion. The flue gas is thus mainly composed of sequestration-ready CO<sub>2</sub>, along with easily condensable water. As combustion with pure oxygen yields very high temperatures, incoming O<sub>2</sub> supplied for combustion is diluted in recycled flue gases (FGR). Desired temperature and flow profiles inside the boiler are thus adjusted for the process to be compatible with today's materials. In this paper, the process of combusting the pulverized-coal



**Figure 6. Oxy-combustion process for CO<sub>2</sub> capture from PC boiler (schematic)**

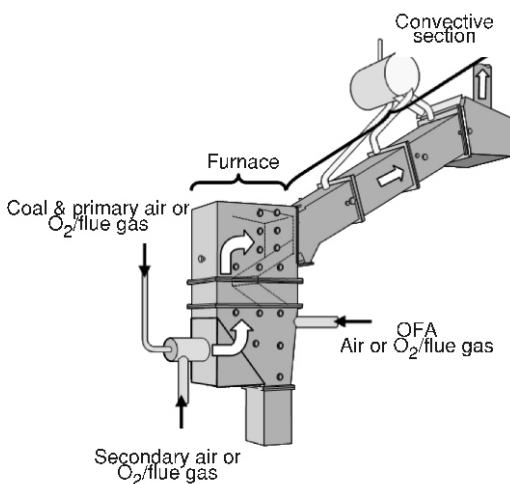
(PC) in an  $O_2$ - $CO_2$  environment using FGR is referred to as “ $O_2$ - $CO_2$  combustion” or “Oxy-combustion” in PC boilers (PC-OC).

In the PC-OC process investigated in this study, a flue gas desulfurization (FGD) system is located before recycling the flue gases to avoid building up sulfur inside the boiler. The Electrostatic precipitator (ESP) removes the particles (ash) to avoid damaging the recycle line. The sulfur and particle free flue gases exiting the system are  $CO_2$ -rich and four to five fold smaller in volume than from a same capacity air-fired boiler. Such drastic reduction leads to cost-effective further purification if needed, to meet the  $CO_2$  specification for reuse (Enhance oil recovery – EOR, Enhanced coal bed methane – ECBM) or sequestration. As measured on the pilot-scale boiler, the PC-OC process reduces the  $NO_x$  emission by up to 60 to 70% vs. a staged air-fired baseline. Hence, a SCR may not be necessary for  $NO_x$  control.

The PC-OC technology offers a wide variety of alternatives. For a new power plant, the amount of FGR would be set to a minimum, enabling more compact design of some boiler equipment. For a retrofit of an existing boiler, the FGR is set so that the heat transfer characteristics of the boiler operation would remain similar to the air-fired case.

### ***Experimental results: $O_2$ - $CO_2$ demonstration on a pilot-scale boiler***

The demonstration part of the project was carried out in collaboration with B&W. The purpose of the demonstration was to prove the feasibility of the PC-OC process and compare the process performances to air-blown combustion.



**Figure 7. 1.5 MW<sub>t</sub> pilot boiler simulator**

The pilot boiler, referred to as a SBS, is depicted in fig. 7. This 1.5 MW<sub>t</sub> (5 million Btu/hr) pilot-scale boiler accurately replicates the combustion and convection characteristics of a full-size utility boiler. The primary, secondary, and overfire air (PA, SA, OFA) of a conventional air-blown boiler were replaced by oxygen-enriched flue gas ( $O_2/CO_2$ ).

Tests were performed with a low-sulfur sub-bituminous coal. The detailed experimental results are reported in an earlier paper [12]. The key results are described in the following sections

The feasibility of switching from air to  $O_2$ -enriched flue gas (oxy-combustion) operation has been successfully demonstrated.

### NO<sub>x</sub> emissions

As shown in fig. 8, the NO<sub>x</sub> emissions were reduced by an average of 65% in the oxy-combustion vs. air-blown baseline. Using B&W's DRB-4Z<sup>®</sup> low-NO<sub>x</sub> burner, the baseline NO<sub>x</sub> emission ranged from 0.24 to 0.39 lb/10<sup>6</sup> Btu when the burner stoichiometry was varied from 0.75 to 1.1. During the oxy-combustion tests, the NO<sub>x</sub> emission dropped to 0.065 and 0.13 lb/10<sup>6</sup> Btu, respectively. Such significant NO<sub>x</sub> reduction is due to the combined effect of flue gas recycle, burner stoichiometry and oxygen injection in the primary air zone. These results justify the assumption used in the economic study, that no SCR would be needed for implementing the oxy-combustion process.

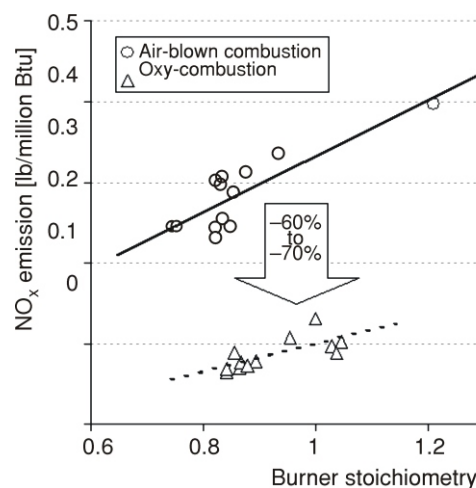


Figure 8. NO<sub>x</sub> emission vs. burner stoichiometry

### Flue gas volume and composition

The flue gas volume exiting the stack was 80% lower in oxy-combustion vs. air-blown combustion, due to pre-combustion removal of the nitrogen. Figure 9 displays the dry flue gas composition. The dry flue gas composition measured from the PC-OC tests was around 80% CO<sub>2</sub> by volume, 3% O<sub>2</sub> and 17% N<sub>2</sub>. Since pure oxygen was used for these tests, the N<sub>2</sub> content in the flue gases was attributed to air-infiltration, caused by some parts of the boiler being operated under negative pressure. In the tests, approximately 5% of the stoichiometry originates from air infiltration. If the air infiltration were completely eliminated, the CO<sub>2</sub> content in the dry flue gases would reach 94 to 95%. Various means to reduce the air ingress and increase the CO<sub>2</sub> concentration in the flue gases are currently being investigated.

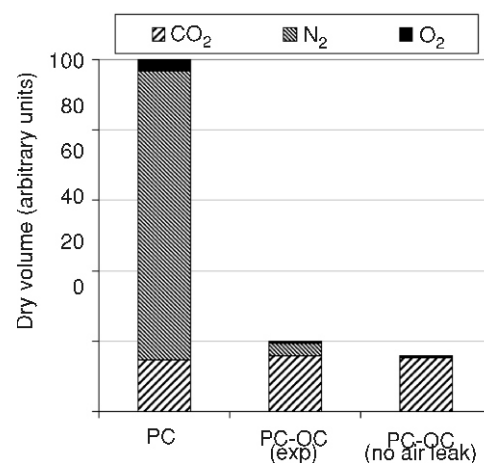
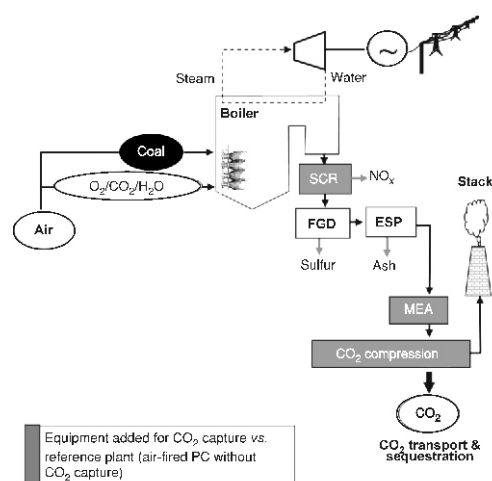


Figure 9. Flue gas volume and composition (exp – measured during experiments; no air leak – if no air infiltration in the system)

### Techno-economic analysis

Two main processes are currently being investigated for CO<sub>2</sub> capture from PC boilers:

- the PC-OC process, that separates N<sub>2</sub> from O<sub>2</sub> prior to combustion to yield CO<sub>2</sub>-rich flue gases (see fig. 6), and
- the post-combustion process, that uses amine-type sorbent to scrub the CO<sub>2</sub> from nitrogen rich flue gases produced via air-firing (see fig. 10).



**Figure 10. Conventional air-fired coal-combustion equipped with Amine scrubber for CO<sub>2</sub> capture (schematic)**

The techno-economic comparison between those two technologies was performed by ISGS with inputs from AL and B&W. Table 3 summarizes the plants investigated in this study.

Both new plants and retrofit applications were considered for application to PC Boilers. The following sections focus on the retrofit results, as many of the existing coal fleet may have to consider reducing their CO<sub>2</sub> emission in a near future. Results for new plants, including comparison to IGCC, are detailed in a separate paper [13].

**Table 3. Plants investigated in the techno-economic analysis and corresponding acronyms**

Acronym	Plant description	Comments	Applications
PC	Conventional air-fired pulverized coal boiler	No CO <sub>2</sub> capture. Used as a reference to calculate the increase in cost of electricity, and the cost of CO <sub>2</sub> avoided	
PC-MEA	Air-fired equipped with MEA unit for CO <sub>2</sub> capture	CO <sub>2</sub> capture plant	Retrofit or new plant
PC-OC	PC boiler fired with oxygen-enriched flue gases for CO <sub>2</sub> capture	CO <sub>2</sub> capture plant	Retrofit or new plant
IGCC-S	IGCC equipped with a selexol unit for CO <sub>2</sub> capture	CO <sub>2</sub> capture plant	New plant

### Process simulation

To represent most of the existing boilers likely to be retrofitted, a sub-critical steam cycle for power generation was assumed in all the cases. CHEMCAD software was used for process simulation and calculation of mass and energy balances. The process was divided into four parts, coal combustion, steam generation, flue gas cleaning and either CO<sub>2</sub> capture by MEA or O<sub>2</sub> generation by air separation unit (ASU). Flue gas cleaning consists of ESP for ash removal, lime spray dryer (LSD) for SO<sub>x</sub> and SCR for NO<sub>x</sub>. Typical design and operating conditions of these processes were obtained from literature [14-17].

The gross power output was fixed at 533 MW<sub>e</sub> in all the cases, which provides approximately 500 MW<sub>e</sub> net output under air-firing conditions. The processes listed above consume significant amounts of energy/electricity (auxiliary power), especially the ASU, the MEA, and the CO<sub>2</sub> compressor, which impact the net output (gross power output – auxiliary power) of the power plant. The net plant efficiency is defined as the ratio between net power output and total thermal input. The key process assumptions are summarized in tab. 4.

**Table 4. Key assumptions for process simulation**

Gross power output	533 MW <sub>e</sub>
O <sub>2</sub> purity	99%
Fuel	PRB coal
Power generation	Subcritical steam turbine
MEA	Fluor Daniel Econamine FG process with 90% solvent efficiency
LSD and SCR	90% efficiency

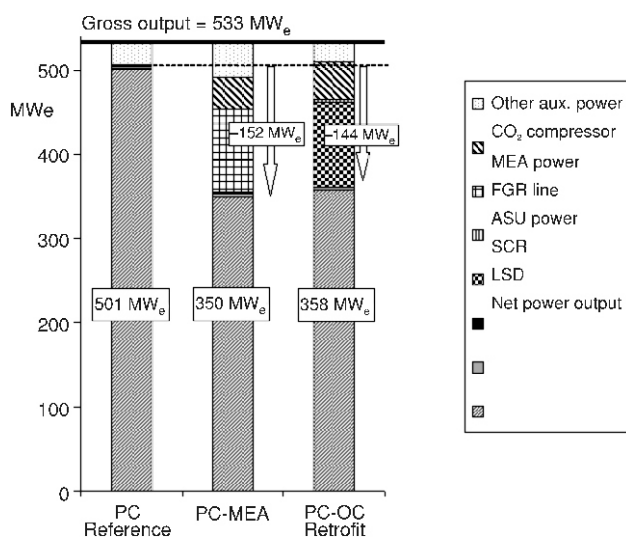
The performances of the PC plant (reference), PC-MEA, and PC-OC units are presented in tab. 5 and fig. 11.

A stand alone (no integration) 8,800 metric ton per day (mTPD) ASU used in the PC-OC process consumes about 100 MW<sub>e</sub> (about 19% of the gross power output). The PC-MEA process uses steam for amine regeneration, decreasing the net power output by about 98 MW<sub>e</sub>. The CO<sub>2</sub> compression to 80 bar is the next major auxiliary power, reducing the net power output of a “capture plant” by about 40 MW<sub>e</sub> vs. reference PC plant. Overall the net power output is reduced by 28% and 30% from an existing 500 MW<sub>e</sub> net plant when retrofitted with OC and MEA, respectively.



**Table 5. Overall performances of the plants**

	PC	PC-MEA	PC-OC
Gross power [MW <sub>e</sub> ]	<b>533</b>		
Other aux. power [MW <sub>e</sub> ]	19	41	23
CO <sub>2</sub> compression [MW <sub>e</sub> ]		38	45
MEA power [MW <sub>e</sub> ]		98	
FGR line [MW <sub>e</sub> ]			3
ASU power [MW <sub>e</sub> ]			101
SCR [MW <sub>e</sub> ]	3	3	
LSD [MW <sub>e</sub> ]	3	3	3
Net power [MW <sub>e</sub> ]	<b>501</b>	<b>350</b>	<b>358</b>
Net efficiency, HHV [%]	37.0%	25.8%	27.3%

**Figure 11. Overall performances of the plants**

### Cost assessment

As mentioned before, MEA and ASU units impact the net power output of the plant. In order to take this impact into consideration, all the capital and operating costs are in US\$/kW<sub>e</sub> or \$/kWh based on net kW<sub>e</sub> output.

### Methodology

For assessing cost of the power generation technologies, the classification of 14 process areas recommended by DOE [14, 15] was applied. Three additional specific process areas were considered: CO<sub>2</sub> separation (MEA), O<sub>2</sub> production (ASU) and Flue gas recycle (FGR). The capital

cost of the existing power plant was assumed to be paid off. The capital costs of items added for the retrofit were levelized over a period of 20 years assuming an inflation rate

of 4.1%. Costs associated with operating and maintaining the plant include operating labor, administrative and support labor, maintenance labor and materials, consumables, and coal.

For retrofit cases, only the existing components that need to be modified and new components that must be added were considered. The modifications include the flue gas cleaning systems (modified flue gas flow rates modifies the cost of flue gas cleaning), the addition of the ASU and FGR line (piping, fan, *etc.*) for PC-OC cases, addition of the MEA system for the PC-MEA case, addition of CO<sub>2</sub> compressors in both cases. If the existing unit is already equipped with SCR and/or LSD, those two items may or may not have to be added on the Capture plant. PC-MEA requires both SCR and LSD. PC-OC requires LSD only.

#### Cost of CO<sub>2</sub> avoided

Cost of a CO<sub>2</sub> capture system is generally expressed in terms of either cost per ton of CO<sub>2</sub> removed or cost per ton of CO<sub>2</sub> avoided. For systems like MEA and ASU that are very energy intensive, the costs per ton of CO<sub>2</sub> removed and avoided are very different. To take into account the reduced net power output resulting from CO<sub>2</sub> capture, the cost of CO<sub>2</sub> avoided is more relevant. This economic indicator is calculated using the following formula [18].

Cost of CO<sub>2</sub> avoided (\$/ton):

$$\frac{COE_{cap} \quad COE_{ref}}{(tonCO_{2emitted} / kWh)_{ref} \quad (tonCO_{2emitted} / kWh)_{cap}} \quad (1)$$

where

COE – levelized cost of electricity [\$/kWh],

cap – capture plant (PC-OC or PC-MEA),

ref – reference PC plant without CO<sub>2</sub> capture, and

tonCO<sub>2emitted</sub>/kWh = metric ton of CO<sub>2</sub> emitted by the plant per kWh net generation.

This formula can also be expressed in the following self-explanatory way:

Cost of CO<sub>2</sub> avoided [\$/ton]:

$$\frac{(\$_{added\_equipment})_{cap\_vs\_ref} \quad (\$_{electricity\_loss})_{cap\_vs\_ref}}{tonCO_{2avoided}} \quad (2)$$

where

$\$_{added\_equipment}$  – levelized capital and O&M cost of the equipment added on an existing PC unit to capture the CO<sub>2</sub> (ASU, FGR, MEA, CO<sub>2</sub> compressor *etc.*...),

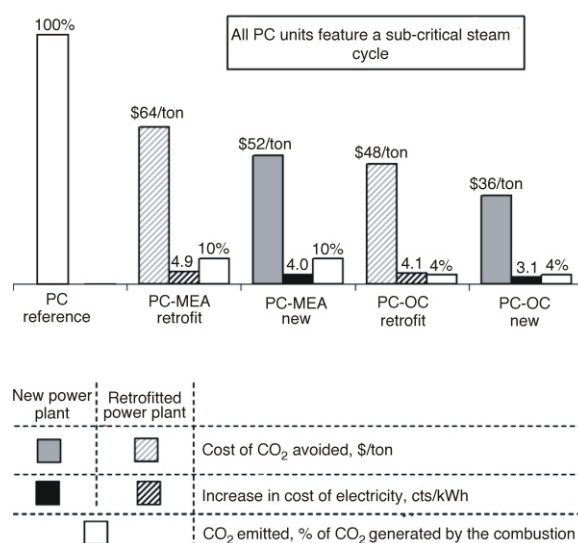
$\$_{\text{electricity\_loss}}$  – cost of the net power lost from existing PC unit to the retrofitted capture plant, and  
 $\text{tonCO}_{2\text{avoided}}$  – metric tons of  $\text{CO}_2$  avoided =

$$\frac{(\text{tonCO}_{2\text{emitted}})_{\text{ref}} - (\text{tonCO}_{2\text{emitted}})_{\text{cap}}}{\frac{\text{tonCO}_{2\text{emitted}}}{\text{kWh}}_{\text{ref}}} \Delta \text{kWh}_{\text{ref-cap}} \quad (3)$$

where  $\text{kWh}_{\text{ref-cap}}$  – decrease in kWh net output from reference plant to capture plant.

### Results of economics study

Figure 12 shows the two key economic indicators used to compare the PC-OC and PC-MEA processes: the increase of cost of electricity (COE increase, in mills/kWh) and the  $\text{CO}_2$  avoidance cost (in \$/ton  $\text{CO}_2$  avoided). For the purpose of comparison with other studies, that often report the indicators corresponding to new power plants only, the results for new power plants are also displayed in fig. 12, in addition to the retrofit numbers. The economic indicators of a retrofit unit differ from those of a new unit because of different reference plant and slightly different process. As mentioned earlier, the reference plant for retrofit application does not have SCR nor LSD, whose costs thus contribute to the \$/ton  $\text{CO}_2$  avoided. SCR and LSD are included in a reference plant for a new unit.

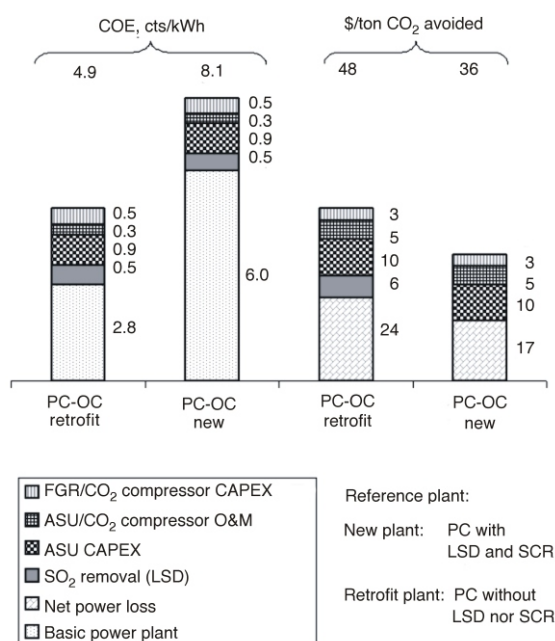


**Figure 12. Increase in cost of electricity (cts per kWh) and  $\text{CO}_2$  avoidance costs (\$ per ton)**

For retrofit application, the levelized COE was increased by 4.9 cents per kWh for the PC-MEA and by 4.1 cents/kWh for PC-OC process. This higher increase for PC-MEA *vs.* PC-OC is due to the combined effect of higher capital and operating costs and slightly lower net power output.

The PC-OC plants show significant cost reductions in term of cost of CO<sub>2</sub> avoided relative to a plant with MEA unit. The CO<sub>2</sub> avoidance cost obtained for PC-MEA plant was \$52/ton and \$64/ton for new and retrofit units respectively. These costs were around \$36/ton and \$48/ton for the PC-OC new and retrofit plants, *i. e.* 25 to 30% lower than the PC-MEA costs. Note that for both cases, the cost of CO<sub>2</sub> avoided includes the costs of compression to 80 bar.

In order to better understand the impact of the various plant components on the electricity and CO<sub>2</sub> avoidance costs, a detailed breakdown of those costs is displayed on fig. 13.



**Figure 13. Cost breakdown of the COE and CO<sub>2</sub> avoidance cost of the PC-OC process for new and retrofit applications**

For both new and retrofit PC-OC the key item impacting the cost of CO<sub>2</sub> avoided is the loss of net power output, that accounts for about half of the overall cost of CO<sub>2</sub> (48%, \$17 to \$24/ton). The ASU capital cost accounts for about one fourth of the CO<sub>2</sub> avoided cost (21 to 28%, about \$10/ton). ASU capital is site specific as the construction cost is a major component. In this study, an Illinois location has been selected, where the

labor cost is about twice the labor cost on US gulf cost basis (USGC, a common basis for engineering cost estimate). The required capital of a FGR recycle line and CO<sub>2</sub> compressors represents less than 10% of the CO<sub>2</sub> avoidance cost (less than \$4/ton). If there is no sulfur removal on the reference unit, adding the LSD contributes to about 13% (about \$6/ton) to the CO<sub>2</sub> avoided cost.

Lowering the cost of CO<sub>2</sub> avoided from the PC-OC process will thus primarily result from lowering the auxiliary power consumption, including the ASU power consumption. If the ASU requirement were reduced from 100 MW<sub>e</sub> (19% of gross power output) to 70 MW<sub>e</sub> (13% of gross power output), the CO<sub>2</sub> avoided cost could be decreased below \$30/ton. Various efforts are in progress that are expected to lead to significant reduction of the ASU power need.

## Conclusions

In addition to a number of existing uses in industrial combustion processes, oxygen has significant potential applications in the field of power generation. Two specific technologies for pulverized-coal (PC) boilers have been described:

- oxygen-enriched Combustion (OEC) for NO<sub>x</sub> control, and
- oxy-combustion (PC-OC) for CO<sub>2</sub> capture, with added benefit of major NO<sub>x</sub> reduction.

**The OEC technology** provides a breakthrough NO<sub>x</sub> control option to the utility industry that enables reduction of NO<sub>x</sub> emissions to lower levels than with today's most widely implemented combustion modifications for NO<sub>x</sub> control (OFA and LNB). OEC is potentially more affordable than the current SCR technology, although this depends on many factors such as retrofit difficulty, size of unit, plant remaining life, boiler capacity factor, *etc.* Especially, the OEC technology is much less capital intensive than the SCR.

Preliminary experimental data have confirmed the potential of oxygen enrichment for NO<sub>x</sub> reduction. Results obtained in pilot-scale tests (1.5 MW<sub>t</sub> and 30 MW<sub>t</sub>) with two very different types of coal showed up to 30% NO<sub>x</sub> emission reductions from an air-staged baseline. These results were very sensitive to the O<sub>2</sub> introduction arrangement and to the O<sub>2</sub> enrichment level.

In addition to its overall cost competitiveness and the reduced capital requirements, the O<sub>2</sub>-enriched low-NO<sub>x</sub> technology provides other significant advantages compared to existing technologies: (1) the technology does not involve the use of chemicals such as ammonia or catalyst, which will facilitate the permitting process for the utility industry, (2) the retrofit itself will be a low risk project since very little plant modification will be necessary, and (3) the footprint requirements are smaller than for SCR, which enables the technology to be implemented in space-limited power plants. Finally, further benefits are expected such as combustion efficiency increase, flame stabilization, and plant capacity increase.

**The PC-OC technology** was shown to be a cost-effective technology for CO<sub>2</sub> capture from retrofitted or new PC plants. Removing the nitrogen prior to combustion of-

fers many advantages compared to post-combustion separation from the air-fired flue gases.

The PC-OC has been successfully demonstrated on a 1.5 MW<sub>t</sub> pilot boiler. The tests showed similar heat transfer and flame characteristics under an optimum oxy-combustion conditions as in air-firing conditions, in spite of very significant changes in oxidizer composition from air to oxygen-enriched flue gas. This was a key result to open new opportunities for retrofit application of the technology without costly pressure part modifications. In addition, the PC-OC technology reduces NO<sub>x</sub> emissions by 60 to 70% below the air-blown staged baseline. No further NO<sub>x</sub> control technology is likely to be needed. Air infiltration has been limited to 5% of the overall stoichiometry, resulting in 17% nitrogen by volume in the dry flue gases (80% CO<sub>2</sub>). Depending on the CO<sub>2</sub> application (site specific), the flue gas may have to be further processed. Alternative boiler upgrade and flue gas purification technologies are expected to lead to the required CO<sub>2</sub> purities. All processes for further purifying the flue gases will benefit from the reduced flow rate to be treated (70% lower than in air-combustion).

Process calculations and economic analyses have been performed on PC-MEA and PC-OC 533 MW<sub>e</sub> gross units, for retrofited and new plants. Both capture technologies impact the power plant net power output, increasing the cost of electricity. The impact seemed to be more significant for the PC-MEA process than for the PC-OC processes. The net power output was reduced by 30% with the PC-MEA system. The reduction is about 28% with the PC-OC process, 19% being due to the ASU power consumption. The cost of CO<sub>2</sub> avoided was around \$36/ton for the new PC-OC cases, about \$48/ton on a retrofit PC-OC case, and \$52 to \$64/ton for the PC-MEA new and retrofit cases, respectively. Those numbers are calculated for subcritical units and include the cost of CO<sub>2</sub> compression.

The performances and cost-efficiency of both oxygen-based technologies can be further optimized, while addressing the specifics of the utility industry and ensuring the safety of the proposed solution. To meet such a challenge, AL and B&W will combine their respective expertise in oxygen production and in coal-fired boilers.

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### Abbreviations

AL	– Air Liquide
ASU	– air separation unit
B&W	– the Babcock & Wilcox company
BSR	– burner stoichiometric ratio
DOE	– Department of energy
ECBM	– enhanced coal bed methane
EOR	– enhanced oil recovery
ESP	– electrostatic precipitator
FGD	– flue gas desulphurization
FGR	– flue gas recycle
IGCC	– integrated gasification combined cycle
ISGS	– Illinois State Geological Survey
LNB	– low-NO <sub>x</sub> burners
LSD	– lime spray dryer
MEA	– monoethanolamine
NETL	– National energy technology laboratory
NO <sub>x</sub>	– nitrogen oxides
OEC	– oxygen-enriched combustion
OFA	– overfire air
PC	– pulverized coal
PC-OC	– oxy-combustion in pulverized coal boilers
PRB	– powder river basin
SBS	– small boiler simulator
SCR	– selective catalytic reduction
SNCR	– selective non-catalytic reduction
TPD	– ton per day
USGC	– US gulf coast

### Nomenclature

CAPEX	– capital expenditure, [\$]
COE	– levelized cost of electricity, [\$/kWh]



O&M – operating and maintenance cost, [\$]  
 ton – metric tons

### Subscripts

cap capture plant (PC-OC or PC-MEA)  
 ref reference PC plant without CO<sub>2</sub> capture

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