Power Engineering Magazine

Comparing Emissions: PC, CFB and IGCC

March 2007

Data from operating coal plants offers insight, and a few surprises, on comparable emissions.

By Robynn Andracsek, Burns & McDonnell

The resurgence of coal-fired generation over the past 10 years has been accompanied with a great deal of confusion and controversy over related environmental issues, specifically air quality and air emissions. This article compares the available numerical facts regarding air emissions among the three main types of coal-fired electrical generation.

Each of the three main types of coal-fired power plant technology has its own distinct characteristics. A detailed discussion of their merits, differences and attributes will not be attempted here. However, the following is a primer.

Pulverized Coal (PC) - In a PC boiler, crushed coal is pulverized to a fine powder and blown directly to individual burners where it is mixed with pre-heated combustion air and combusted in a flame. The heat energy from the combustion process is used to produce steam which drives a turbine-generator set to produce electricity.

Circulating Fluidized Bed (CFB) - In a CFB boiler, the crushed coal, normally mixed with crushed limestone, is fluidized by passing pre-heated combustion air upward through a distributor plate. Combustion occurs in the fluidized zone above the distribution plate. The limestone reacts with sulfur from the coal to reduce emissions of sulfur oxides. Heat recovery, steam production and electricity generation are as described for the PC boiler.

Integrated Gasification Combined Cycle (IGCC) - In the IGCC process, coal is transformed into a synthetic gas under pressure and temperature. The syngas is processed to remove impurities such as sulfur and particulates. The cleaned syngas is fired in a combustion turbine that drives a generator to produce electricity. The hot exhaust from the turbine is passed through a heat recovery steam generator (HRSG) to produce steam used to drive a second turbine-generator set.

Regulated Pollutants

National Ambient Air Quality Standards (NAAQS) have been issued for seven pollutants. These are known as criteria pollutants: sulfur dioxide (SO2), nitrogen oxides (NOX), particulate matter less than 10 microns in diameter (PM10), particulate matter less than 2.5 microns in diameter (PM2.5), carbon monoxide (CO), ozone and lead.

Modified NAAQS for PM2.5 have recently been promulgated but are not yet in effect. Permitting of a coal-fired boiler focuses on SO2, NOX and PM10. Ozone is addressed through controlling emissions of volatile organic compounds (VOC). VOC and CO are typically controlled via good combustion practices and are rarely the focus of the permitting effort. Lead is often below the significance level and is usually treated as being controlled concurrently with PM10.

At the state level other pollutants may be regulated, such as total suspended particulate (TSP) or specific hazardous air pollutants (HAPs). CO2 is not currently regulated in the United States.

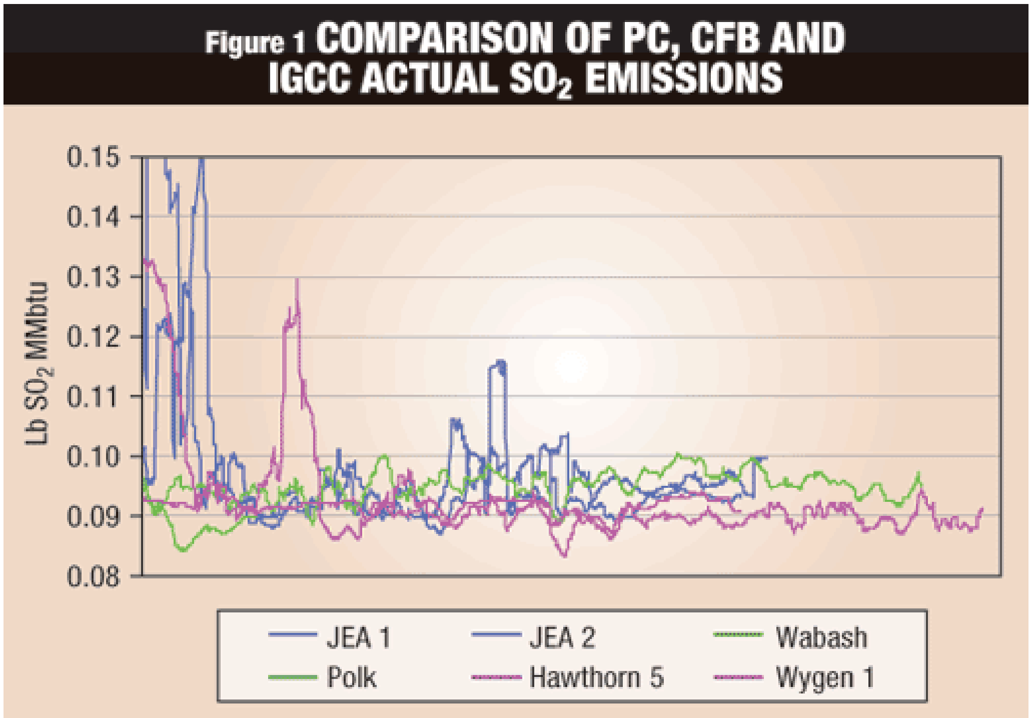
Mercury is currently regulated in the Clean Air Mercury rule (CAMR), which was first promulgated in 2005 and revised in 2006. Previous to this promulgation, major sources of mercury underwent a case-by-case MACT analysis. Now that the CAMR is in effect, previous mercury MACT determinations are moot and will not be compared here. However, the CAMR itself deserves an important clarification.

The CAMR was first "final" in May 2005 and then "reconsidered" and finalized again in June 2006. The applicable new source performance standard (NSPS) mercury limits for units using different types of coal were revised in several cases. The "reconsidered" final rule is confusing due to the revised usage of the terms "wet" and "dry". Under the old, now obsolete May 2005 rule, wet and dry referred to the FGD technology used. The current final version of CAMR defines wet and dry based on the average rainfall of 25 inches as the dividing line between wet and dry areas of the country. Hence, the seemingly simple terms of wet and dry are now ripe for confusion. Care should be taken when referring to the CAMR limits that the appropriate definitions are applied when the new unit will fire sub-bituminous coal.

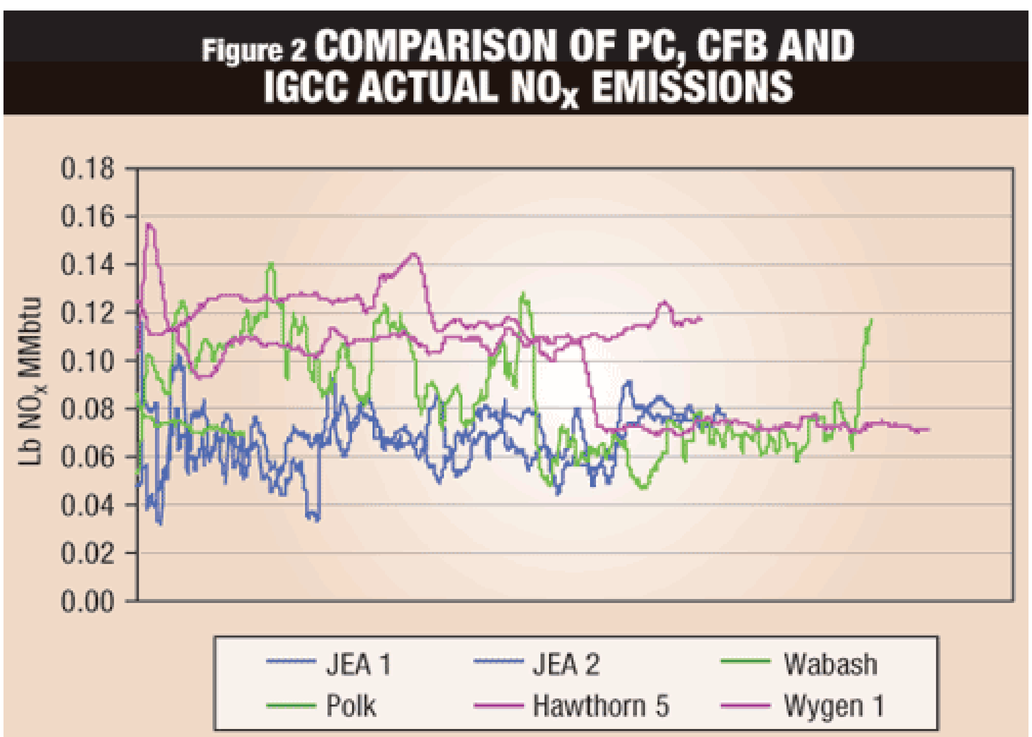
Actual Emissions

Each electric generating unit subject to 40 CFR Part 72-77 (Acid Rain) is required to report SO2, NOX and CO2 emissions as well as heat input to the EPA on a quarterly basis. Using this data, the historical actual emissions for the 30-day rolling average from PC, CFB and IGCC units on a lb/MMBtu basis were determined and are compared in Figures 1, 2 and 3. The specific PC and CFB plants chosen were the most recent ones with several years of operating data available.

The facilities used in this comparison are JEA Northside 1&2 for CFB, Hawthorn 5 and Wygen 1 for PC and Polk and Wabash for IGCC. The data was taken from the Clean Air Markets (Data and Maps) website, found in the "Emissions Prepackaged Data Sets" at http://cfpub.epa.gov/gdm/index.cfm. The PC and CFB data were adjusted for valid "boiler operating days" as required in NSPS Subpart Da. The IGCC data, although not subject to NSPS Subpart Da, was likewise adjusted to make the comparison equal. Therefore, the X axis in Figures 1 and 2 represents consecutive qualified boiler operating days, beginning with the date when CEM data was first reported to EPA and extending through the third quarter of 2006.



As shown in Figure 1, there are no distinct differences in reported SO2 emissions between the three unit types. Variability in the fuel sulfur content is reflected in the data spikes and troughs. Also evident is the time taken to recover from a start-up, shutdown or upset event.

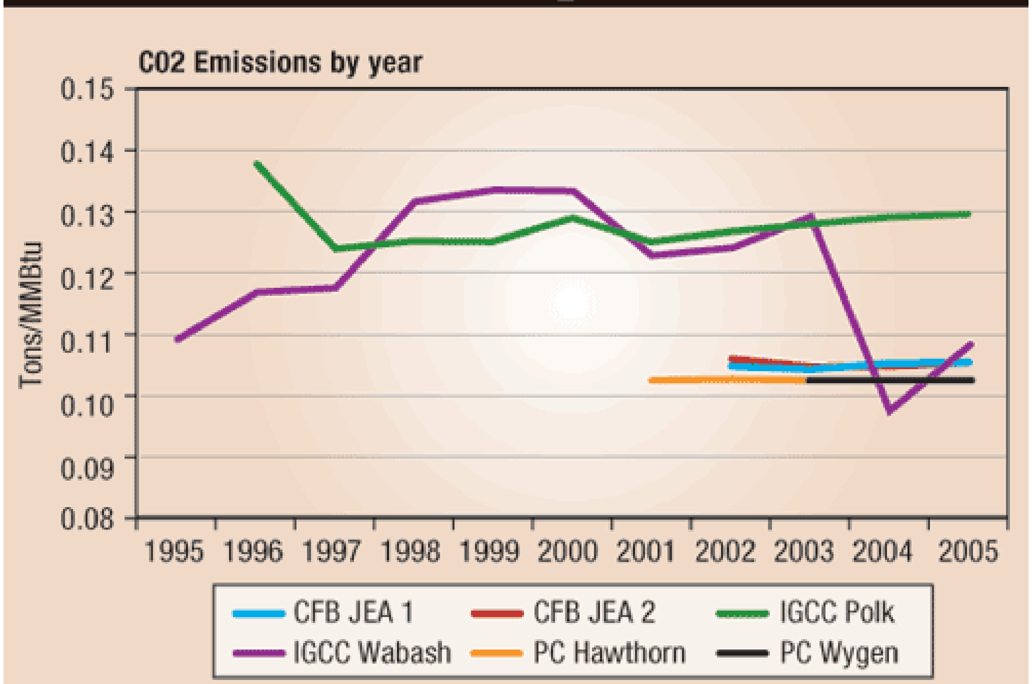


The NOX data in Figure 2 shows the extreme variability in the early life of each unit as it undergoes commissioning. The data lines converge as each unit ages. Note, too, the sharp drop in NOX emissions for one of the PC units. This is due to the expiration of a demonstration period and the improved operation of its selective catalytic reduction (SCR) system due to complete change out of the catalyst.

Carbon Dioxide

Carbon dioxide is currently not a regulated pollutant in the United States. Questions of whether it should be regulated will be determined in the political arena. One certainty is that CO2 is emitted by all three types of coal-fired power plants and all electric generating units subject to the Acid Rain program are required to report CO2 emissions to the EPA.

Figure 3 COMPARISON OF PC, CFB AND IGCC ACTUAL CO_2 EMISSIONS



The CO2 data in Figure 3 shows that reported CO2 emissions from PC and CFB units are considerably lower than the reported IGCC CO2 emissions. This is contrary to what would be expected. Note that the units of measurement are tons/MMBtu not lbs/MMBtu and that the data is for annual totals, not 30-day rolling averages. There is very little noise or variability in the data for CFB or PC units, indicating that CO2 per million Btu is not particularly changeable. For CFB and PC, the carbon in the fuel provides most of the Btu and there are no operating conditions that would cause changes in the degree to which carbon is converted to CO2. Therefore, on a tons/MMBtu basis operating "ups and downs" have little effect on the emission rate.

If CO_2 becomes a regulated pollutant subject to a cap and trade or carbon tax program, measured data would be needed to run an effective program. Concurrently, any unit which uses continuous emissions monitoring (CEMS) for NOX measurement must measure a diluent to convert the NOX emissions to standards values. This diluent may be either O_2 or CO_2. New CEMS equipment installed by forward-looking utilities may include selection of CO_2 in lieu of O_2 as a diluent to be better prepared for future CO_2 measuring requirements.

Boiler Operating Day

PC and CFB boilers are both subject to 40 CFR Part 60 Subpart Da, "Standards of Performance For Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978". Compliance with the NOX and SO_2 limits in Subpart Da is based on a 30-day rolling average. However, only "boiler operating days" are required to be included in the average.

The Standard's 40 CFR 60.41Da says: "Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours".

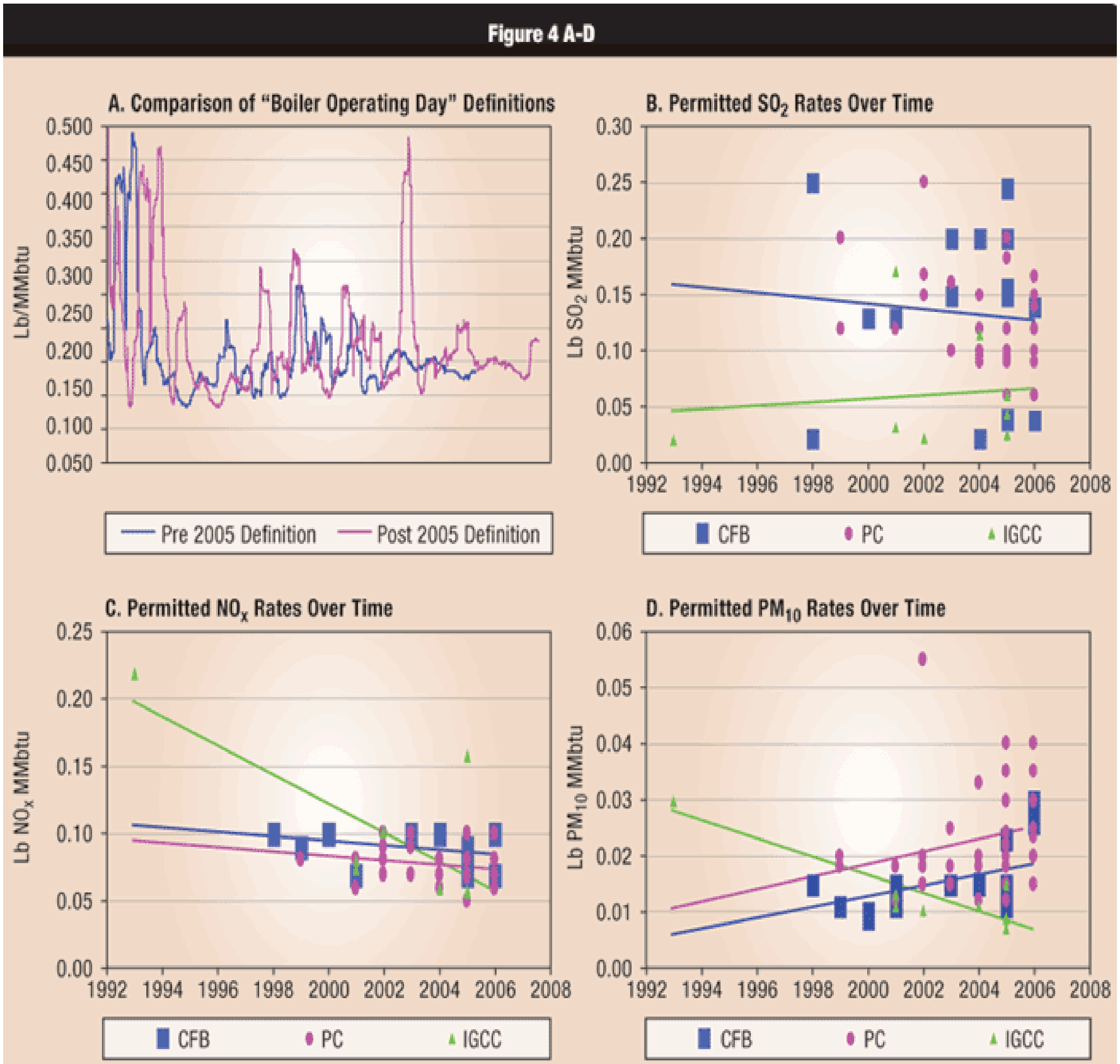
For units constructed, reconstructed or modified after February 28, 2005, boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period."

Eliminating some data from the 30-day average removes most data outliers caused by start-up, shutdown and upset operation. Pre-2005 units are allowed to remove more data than the post-2005 units, which makes compliance different for the pre-2005 units. Therefore, when data becomes available for the post-2005 units, care must be taken to use the different boiler operating day definitions when determining compliance but the same definition when comparing actual emissions.

As Figure 4-A shows, substantially more valid data exists under the post-2005 definition of boiler operating day. The data shown is for JEA Northside Unit 2 SO_2 emissions.

Permitted Emissions

Very few "next generation" electric generating units are in operation, but quite a few are in the permitting or construction stage. This next generation of units includes ultra-supercritical PC boilers and technical advancements in IGCC, such as advanced gas clean-up technology and general improvements in metallurgy. The next generation incorporates the experience gained from existing units. Therefore, it is valuable to compare the permitted emission rates over time - from 1992 to 2006 - resulting from the variability of sulfur content in fuel. IGCC trends lower than PC and CFB. Likewise, permitted NOX rates for each type of unit approach the same level. There is a slight downward trend in NOX rates for PC and CFB units. These trends are illustrated in Figures 4 B-D.



Counter intuitively, there is an upward trend in PM10 permitted rates for PC and CFB units. The PC and CFB data shown is a mix of "filterable only" and "filterable plus condensible" limits, since some state agencies do not include condensible particulate in their issued permit limits. The upward trend reflects concerns about the available test methods for condensibles, specifically, creation of "artifacts" during Method 202. Artifacts are created from the oxidation of SO2 to SO3 in the "back half" impinger, from ammonia slip (from the NOX control device) reacting in the impinger to form ammonium bisulfate and absorption of soluble NOX components (such as N2O5). These materials are created in the sampling system by the measurement technique itself and are read as condensible particulate matter. Permitted PM10 rates from IGCC units trend the lowest.

Few next generation power plants are currently in operation, but more permit applications are being submitted each year. The permitted pollutant emission rates for those not yet in operation are trending downwards, with the exception of PM10.

The biggest questions are these: Will EPA approve a PM10 test method that accurately represents condensible emissions? Will CO_2 become a regulated pollutant? How will the revised PM2.5 NAAQS affect new electric generating units?

Resolving these questions will affect the PC-to-CFB-to-IGCC emission comparison, but likely not until more new generation units are in operation, probably within the next five to 10 years.

Author: Robynn Andracsek is a senior environmental engineer with Burns & McDonnell specializing in air quality permitting. She helps industrial and utility clients prepare operating and construction air permits, provides regulatory interpretations, conducts historical audits and emission calculations and addresses other critical air permitting issues. She wishes to thank Principal Air Pollution Control Engineer Carl Weilert for his assistance in preparing this article.

Post Combustion Carbon Capture

By Steve Blankinship

Regardless of how well coal-fired power technologies remove various emissions, CO_2 dominates today's debate about new coal plants because it is the primary greenhouse gas that coal plants produce. Conventional wisdom has held that the technology with the most promise to capture CO_2 is IGCC. That's because capturing all emissions - CO_2 included - is easier when coal is in a gasified state prior to being burned, than captured from flue gas after combustion.

But a 5 MW pilot plant in Wisconsin scheduled to go into operation later this year could change that thinking. The plant will test ALSTOM's Chilled Ammonia Process that captures CO_2 from conventional pulverized coal plants post-combustion. If successful, the process could be incorporated into new PC plants and retrofitted to existing ones.

The pilot, at We Energies' 1,224 MW Pleasant Prairie plant, will use chilled ammonia to capture CO_2 from a portion of the flue gas coming from one of the Pleasant Prairie units. The process captures and isolates CO_2 in a highly concentrated form at high pressure. In laboratory tests, the process has shown potential to capture more than 90 percent of the CO_2 less expensively than other carbon capture technologies. The captured CO_2 can then be used commercially or geologically sequestered. The process is also expected to remove high levels of residual SO_2, hydrochloric acid, hydrogen fluoride, SO_3 and condensable particulate matter (PM2.5).

The pilot is being funded privately. In addition to ALSTOM, funding is coming from 19 ERPI-member utilities. "Evaluating and developing technology for economical post-combustion CO_2 capture is critical to ensure that we keep coal as a viable electricity generation option," says Chris Larsen, vice president of generation for EPRI. In addition to We Energies, 19 other U.S.

utilities have committed to support the project.

Sean Black, manager of CO2 programs within ALSTOM's Environmental Control Systems business, said the process takes flue gas, which typically leaves the boiler/flue gas desulfurization unit at about 130 F, and cools it to 32 F to 50 F. After it cools, it passes through a CO2 absorber where it is absorbed with ammonia carbonate. The flue gas then passes through a water wash system, after which the CO2 solution moves to a regenerator where the CO2 is stripped off under pressure and high temperatures. (See Fig. 1.)

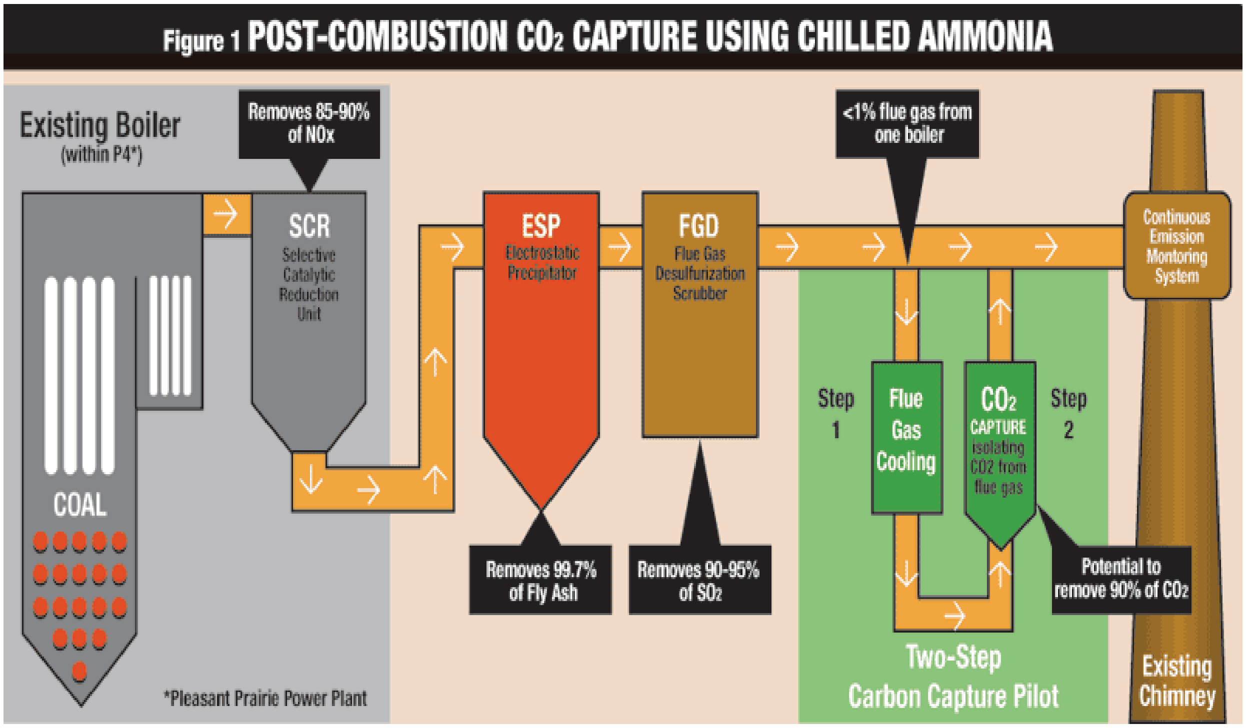


Figure 1 POST-COMBUSTION CO_2 CAPTURE USING CHILLED AMMONIA

The process leaves little byproduct - essentially a small amount of water than can either be treated in a wastewater treatment facility or possibly recycled for use in another part of the power plant. "The process is designed to take advantage of the attractive characteristics of the ammoniated solution while preventing the ammonia from escaping from the system," says Black. The CO2 will be pressurized in accordance with anticipated standards for commercial use, such as transport for enhanced oil recovery or sequestration. If purity standards are required for commercial CO2, Black sees no problems in achieving those standards.

One feature of this technology is that it does not require extremely low levels of SO2 coming into the system for it to work. About 95 percent of the modern designed FGD is sufficient. So most plants already have or will be retrofitting their plants with modern selective catalytic and FGD systems. That means if they have the footprint to install the chilled ammonia CO2 system, a retrofit may be possible with minor adjustments to the steam cycle to accommodate for the process's low pressure steam requirement.

The Pleasant Prairie pilot project is expected to run about a year, after which ALSTOM expects to build one or more demonstration projects, each in the range of 20 to 30 MW. The company expects the chilled ammonia process to be ready for commercial application in 2011.
-Additional reporting by Amethyst Cavallaro.
Power Engineering March, 2007
Author(s) :   Robynn Andracsek