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The Evolution of Emissions Control Technologies to Meet Lower Limits

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Introduction

Coal-fired power generation still accounts for the majority of power generation throughout the Asian continent and is expected to grow along with the expanding economies of the region. Advanced emissions control technologies will be required to operate effectively and efficiently to support the evolving environmental regulations of coal-fired power plants in Asia. The United States (U.S.) has experienced significant advancement of emissions control technologies to meet the evolving and more stringent criteria pollutant emissions such as sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM) to minimize ambient air concentrations of PM10, PM2.5 and ozone as well as increased visibility. In addition there has been increasing emphasis on the reduction of hazardous air pollutants such as mercury (Hg) and heavy metals.

The primary technologies that have been employed to meet low pollutant emissions have historically been with flue gas desulfurization (FGD), electrostatic precipitators (ESP), low NO_x combustion systems, and selective catalytic reduction (SCR). Each of these technologies have advanced and evolved over time to overcome the challenges of meeting lower emissions limits. It is worth further examination into each technology to better understand the current state of the art, and what limitations have been overcome to meet lower emissions. A better understanding of these challenges will help guide emissions control technology selection and operation for new power plants.

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U.S. Environmental Legislation

The U.S. passed its first piece of legislation related to air pollution in 1955 called the Air Pollution Control Act. Federal research into air pollution was funded as part of the Air Pollution Control Act primarily as a response to major public health concerns about air pollution in the late 1940s and early 1950s but control of pollution was not part of the legislation. It was not until 1963 when the U.S. passed the Clean Air Act (CAA) of 1963 which sought to establish techniques to control and monitor air pollution. This was followed by the Air Quality Act of 1967 which established the first enforcement proceedings in areas subject to air pollution transport and included extensive ambient monitoring studies. This was a major expansion of studies of emissions inventories, ambient air quality monitoring techniques and air pollution control technologies.

The U.S. government's role in pollution control and environmental enforcement began to take shape in the Clean Air Act Amendments of 1970. Authorization to develop federal and state regulations to limit air emissions was a major part of the legislation which included the creation of four prominent regulatory programs: National Ambient Air Quality Standards, State Implementation Plans, New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants. The National Environmental Policy Act was also passed in 1970 to establish the United States Environmental Protection Agency with the primary focus of the agency being the implementation of the new environmental regulations.

The Clean Air Act was next amended in 1977 with the main component of the legislation being the Prevention of Significant Deterioration of air quality in areas that were already meeting the National Ambient Air Quality Standards (NAAQS). What this essentially did was set a minimum removal efficiency for pollutants from all utility power plants and established permit review requirements to ensure NAAQS attainment which opened the door for many of the U.S. current day regulations.

In 1990 the Clean Air Act was amended a final time resulting in a dramatic expansion of the authority of the U.S. EPA. Also part of the 1990 amendments to the CAA were provisions for the cap and trade system used as part of the Acid Rain Program to take effect in 1995. Phase I of the Acid Rain Program impacted approximately 400+ boiler units in the U.S. while Phase II would encompass over 2000 units. The CAA amendments of 1990 are still referenced today as part of the U.S. EPA emissions rules and regulations including lowered NAAQS for pollutants,

Maximum Achievable Control Technology (MACT), Best Available Control Technology (BACT), Clean Air Interstate Rule (CAIR), Cross State Air Pollution Rule (CSAPR), Regional Haze, the Mercury and Air Toxics Standards and many other revised state programs as part of the State Implementation Plans from the 1970 amendments. The rules and regulations that have been issued by the EPA since the 1990 CAA amendments are the basis of current air pollution controls and emissions limits in the U.S.

China has more recently, over the past 10 years, implemented an extensive program to install flue gas desulfurization equipment on existing utility power plants. Additionally, new power plants have been equipped with FGD and SCR NO_x emissions reduction systems as well as ESP particulate control equipment. In 2011, new regulations were established in China which set very low emission limits, comparable to regulations in the U.S. and Europe for SO_2, NO_x and particulate for coal plants. These limits must now be complied with on all new plants constructed and all existing plants must have been in compliance by July 2014. These new regulations also set objectives for measuring mercury emissions in preparation for future controls.

In most other countries in Asia, desulfurization, NO_x and particulate control systems have been typically supplied as part of new boiler installations. FGD additions on existing boilers have been limited to only a few countries, but may begin to be required by others which have significant un-controlled capacity in the next 5 to 10 years. Growing international and domestic pressures are likely to lead to some increased level of retrofit projects, but the majority of new near-term environmental systems will be part of the equipment that is installed with new power plants.

In addition to the evolving emissions regulations in Asia, environmental protection technologies need to be adapted to a wide variety of coal types. Coals burned in Asia are both indigenous and imported from locations such as Indonesia, Australia and South Africa. Plants are designed to burn traditional lower-sulfur content bituminous coals, but many are being designed for sub-bituminous and anthracite coals. Sulfur contents reflect a wide range as well, from less than 0.5% to more than 4% by weight. Ash, moisture and volatile matter contents also vary widely, affecting the design and selection of environmental protection systems. As a result of both the evolving and varying regulatory emissions limits and the wide variety of coal types being used in Asia, a variety of state-of-the-art emissions control systems will be needed to meet the multi-pollutant requirements for coal-fired power plants.

Electrostatic Precipitators for PM Control

ESPs have a long history of operation prior to any formal U.S. national legislation to control PM emissions. Early practical installations of ESPs in the United States occurred in 1908 after the development of the mechanical high voltage rectifier by Dr. F.G. Cottrell. In 1908

Cottrell recognized that negative corona has advantages over positive and was subsequently awarded a patent for the application of DC high voltage for use in ESPs. The discharge electrode was initially formed from a semi-conducting fibrous material which was important in providing a uniform corona over a long length of wire at a relatively low voltage. Insulation limitations made the high voltage transformers only capable of supplying 10 to 15 kV. Initial applications were in the smelter and cement industries and nearly all the original precipitators were of a vertical tube and axial wire configuration (Figure 1). The first commercial precipitator was applied in 1908 to collect fume and

Figure 1. Vertical tube and axial wire ESP configuration.

dust from the Powder Works of DuPont de Nemours at Pinhole, California. This was quickly followed by another installation at the Lead Smelter at Selby, which successfully collected sulfuric acid mist at a gas flow rate of 2.4 m^3/s. The first ESPs worldwide were mainly used to reduce the worst effects of air pollution, and since there were no emission standards set, the size and installation cost of the ESP was based on the value of the collected materials. Collection efficiencies were therefore generally in the 85 to 90% range. In 1912 a fine wire discharge electrode was developed and patented by Walter Schmidt. This design breakthrough allowed larger ESPs to be constructed with the first of this design being a precipitator installed to treat 472 m^3/s of gas from cement kilns. This plant was very successful and operated for some 50 years.
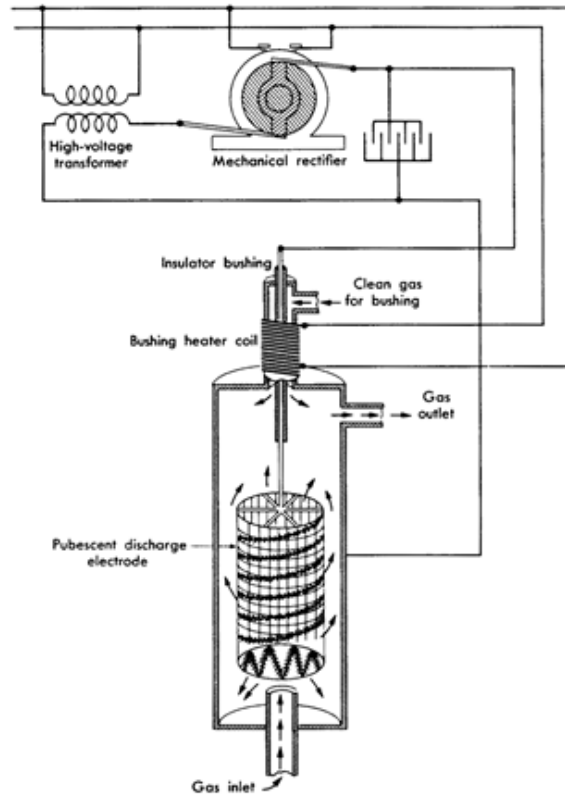
In the early 1920s precipitators were first applied to the power industry following the development of the pulverized coal combustor which was developed because of the need for more electric power and a higher steam rate production during a period of high U.S. industrial expansion. These early combustors carried up to 90% of the fly ash in the furnace gas, compared to 10% from hand-fired, chain grate and similar stoker-fired combustion systems. Since fly ash had little commercial value at the time the ESP was primarily installed for particulate control which is still true today. Prior to 1920 most industrial precipitators were sized and designed by "rule of thumb" approaches, based on the broad foundations established by Dr. Cottrell et. al. Although the basic physics of particle charging and migration were known, it was not until late 1919 and early 1920 that Evald Anderson experimentally established the exponential relationship between efficiency and gas flow, later translated to plant size for the utility industry. Walter Deutsch theoretically proved this logarithmic relationship between efficiency, gas flow and collection area in 1922. Deutsch's equation was later revised in 1926 and became known as the Deutsch-Anderson equation and has been used for almost 50 years by engineers for sizing precipitators having similar dust, process applications and design efficiencies, but differing flow rates. For utility applications during this stage of ESP development the primary design utilized in the U.S. was the horizontal flow, dry plate style ESP with weighted wire discharge electrodes. Collection efficiencies were approximately 95 to 98%. By this time the electric power industry had become the single greatest user of precipitators collecting fly ash from pulverized coal-fired boilers.

While these early ESPs were the groundbreakers of the particulate control industry, the more stringent legislation of the Clean Air Act of 1963 called for power plant emissions to be reduced by a significant order of magnitude, and the Deutsch-Anderson equation was modified by Matts and Ohnfeldt to take into consideration the reduction in emissions. All present day ESP suppliers have adopted some form of the modified Deutsch-Anderson equation for sizing ESPs.

The success and development of the ESP has always been tied to the development of suitable power supplies. There is a need to simultaneously provide a high voltage and corona current for particle charging, and the early electrostatic type generators (Wimshurst machines) were very limited in that capacity. Dr. Cottrell made the technological breakthrough in 1905 by using a high voltage AC transformer coupled to a synchronous mechanical switch rectifier to provide the DC high voltage. The rectifier was mechanically robust and fairly efficient, but noisy,

and needed a large room because of electrical clearance issues, and ventilation since the arcing produced both NO_x and ozone. This form of rectifier was still being supplied (in an updated configuration) as late as the 1960s. The advent of silicon technology in the late 1950s and early 1960s considerably changed the precipitator market. Virtually all installations from the mid 1960s on were fitted with silicon rectifiers. These are vastly superior in terms of efficiency, much smaller in size, and integrate perfectly with the microprocessor-based automatic control systems of the modern era. Collection efficiencies climbed to approximately 99% to meet the stringent requirements of the Clean Air Act.

Advancements in ESP technology over the next several years took place within the control system of the ESP. For many years the only method of controlling voltage and hence the corona current was by means of tap changing on the transformer input. A simple tap change was superseded by an autotransformer or moving coil regulator, where the incoming voltage was modulated by either a hand wheel or a motor drive, as voltage optimization systems were introduced. The next type of control was by use of magnetic saturable reactors or transductors located in the primary circuit, where the output of the device is varied by altering the impedance of the device. This is achieved by a DC current passing through a separate winding on the core of the reactor. Although quite successful these devices were quickly supplanted by the silicon controlled rectifier or thyristor in the early 1960s. These devices control the power into the transformer by modulating the firing angle of the incoming supply voltage and are superior to previous methods of control. In the 1950s the need to maximize voltage for optimal ESP performance was recognized and the development of automatic voltage controls (AVC) began. The early AVCs were electro-mechanical systems where either the voltage or the current was monitored and action taken if certain values were reached or exceeded. The systems were very basic in concept and led to speculation as to whether voltage or current was the best approach. Modern systems use both voltage and current to fully optimize performance. Several forms of wholly electrical devices were developed using thermionic valves or magnetic amplifier devices, but the rapid development of silicon technology in the 1960s quickly superseded them. Initially simple analog-analog designs were used, then digital, and finally microprocessor-based, silicon high speed switching systems. The latest controls use stand-alone microprocessors with software that can make the ESP totally automatic in terms of operation. Generally these systems integrate

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seamlessly with plant DCS systems. These advancements in controls allowed the ESP to achieve 99.5% removal to meet the demand of the CAA amendments of 1990.

Further U.S. EPA regulations such as CSAPR, the Mercury and Air Toxic Standards and the lowering of the PM_{10} and $PM_{2.5}$ NAAQS pushed ESP technology to its current design where, dependent on the fuel ash content and local legislation, can collect in excess of 99.9% of the fly ash (Figure 2). The current modern, state-of-the-art ESP design includes the following features:

- General Sizing Criteria – Gas velocity: 0.85 to 1.1 m/s; aspect ratio: 0.8 to 1.5; fuels burned; moisture in gas; additional dust loading and ash chemistry as a result of dry sorbent injection (DSI) for SO_x or mercury control.

- Gas Distribution – Computer Fluid Dynamics (CFD) flow modeling should be used to make sure the gas and dust flow to the ESP inlet is uniform; typically to meet ICAC EP-7 standards.

- HV Rigid Discharge Electrodes (RDE) – are typically a rigid pipe type with a series of 40 mm long corona-emitting points welded to the pipe. The RDEs are either self-supporting or mounted in support frames. RDEs were developed to avoid the mechanical fatigue and electrical erosion of fine wire electrodes that led to eventual failure and caused ESP reliability problems.

Figure 2. Modern ESP design.

- HV Insulators – are alumina (minimum 85% content) support insulators for today's higher operating voltages. The old style porcelain insulators had much lower breakdown voltage, were porous to moisture which led to tracking, and had lower compressive strength, which often led to a short operational life.

- Power Supplies – There are essentially three choices for modern ESP power supplies: 1) a conventional single-phase power input transformer rectifier operating at 50 to 60 Hz, 2) a low frequency three-phase transformer-rectifier operating at 300 to 500 Hz with a three-
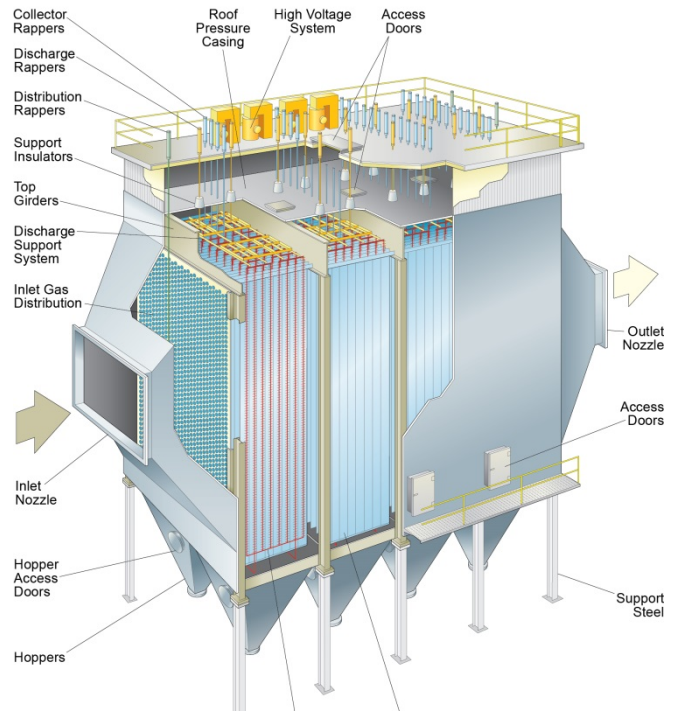
phase power input, and 3) a high frequency power supply operating at about 20 kHz with a three-phase power input.

Extensive lab testing and subsequent field testing by Babcock & Wilcox (B&W) has shown that three-phase low frequency (300 to 500 Hz) T/R sets have several benefits over conventional single phase (50/60 Hz) and high frequency (>20 kHz) switched mode power supplies. The three-phase low frequency T/R set has been used with ESPs for about 25 years, is simpler in design than the high frequency units, and provides the same reliability as single phase T/R sets. The three-phase low frequency design uses a separate control designed by B&W, the SQ-300®*i* control. It is similar to the single-phase design, but has three smaller, more integrated silicon controlled rectifier stacks in the AVC cabinet. Since the controls are separate from the power supply, they can be housed in any convenient location and in a suitable electrical control environment. Modern controls include hybrid automatic voltage controls supplied to control power input to the precipitator.

Since the utility industry started using precipitators, collection efficiencies have steadily increased, from about 85% in the 1920s, to 92 to 98% in the mid 1950s and 1960s, to present day levels of 99.9% to meet the requirements of the U.S. EPA regulations. Table 1 outlines the major changes in characteristics for dry ESPs over time.

Table 1. Chronological ESP Technological Advancements

	1915	1920-1960	1960 - 1980	1980 - 2000	2000-Present
Typical Configuration: • Collecting electrode	130 mm tube	Flat plate	Baffled flat plate, 1.2 mm thick	Baffled flat plate, 1.2 mm thick	Baffled flat plate, 1.2 mm thick
• HV discharge electrode	Iron wire, 3.6 mm dia.	Fine steel 2.7 mm dia. wire	Fine steel wire, 2.7 mm dia.	Fine steel wire, 2.7 mm dia.	Rigid tube 40 mm dia. with pins
• Gas passage spacing	130 mm	230 mm	230 mm	300 mm	400 mm
• HV Insulator Materials	Glass, Mica	Porcelain	Porcelain	Porcelain or Alumina	Alumina

• HV Power Supply	Single phase transformer	Single phase transformer	Single phase transformer	Single phase transformer or High req. SMPS	Single phase transformer or High freq. SMPS, or Low freq. 3-phase transformer
• Rectifier	Mechanical Rectifier	Mechanical Rectifier	Silicon Controlled Rectifier	Silicon Controlled Rectifier	Silicon Controlled Rectifier
• Voltage Controls	None	Analog	Analog or Micro-processor	Micro-processor	Micro-processor
Secondary voltages	30-40 kV	45 kV	45 kV	45 – 65 kV	60-100 kV
Efficiency, %	85 – 90	90.0 – 97.5	99.0	99.5	99.9+

Existing ESPs can be upgraded to meet more stringent emissions requirements. The upgrades will depend on the condition of the ESP, the fuels to be used, whether or not dry sorbent injection is required, emissions level required, and often the space available in the plant. The first step is usually a detailed inspection of the ESP, followed by an engineering study. The study will examine the physical size of the ESP, the resistivity of the ash to be collected, the impact of DSI, etc., and will provide options to meet plant goals.

In order of cost to implement, the following upgrades may be considered:

1. Maintenance and repair of the existing ESP
2. CFD flow model study
3. Replacement of obsolete AVC controllers
4. Additional power supplies and sectionalization of the ESP fields
5. Replacement of AVCs and conventional transformer-rectifiers with low frequency three-phase transformer-rectifiers, or high frequency switch-mode power supplies
6. Rebuild the ESP internals in kind, including rapping systems
7. Rebuild the ESP internals to increase the collecting surface area by increasing the height of collecting plates or rebuilding to a top rapped design
8. Add fields or chambers to the existing ESP (increasing collecting surface area)

NO$_x$ Control Using SCR Technology

In the early phases of the U.S. Clean Air Act, NO$_x$ emissions limits could be achieved primarily using techniques to control fuel-air mixing rates and optimization of combustion temperatures. Additionally, careful fuel selection and selective fuel switching also done in conjunction with low NO$_x$ combustion technology helped to further minimize NO$_x$ emissions. Using all of the above methods in combination could achieve NO$_x$ removals of up to about 50%. However, with further revisions of the Clean Air Act, combustion technologies alone were no longer enough to meet required emissions.

Due to the need for further post-combustion NO$_x$ control, selective catalytic reduction (SCR) systems were first developed in the early 1960s. This early research focused on catalyst formulations and structural integrity of the catalyst. These early catalysts featured expensive materials of construction that utilized precious metals such as platinum. Eventually platinum was replaced by more cost effective materials such as vanadium, titanium and tungsten. The first commercial installations of SCR systems on a utility power plant occurred in 1978 following many pilot plant installations in the early 1970s. Catalyst materials continued to be a major focus of SCR development and in the 1980s metal oxides were employed to broaden the reaction temperature range. Chemical formulations have continued to be modified to continue lowering the costs of employing SCR systems.

The most common chemical agents used in commercial applications for SCR systems are anhydrous ammonia, aqueous ammonia (19 to 29% concentration) and urea. When urea is used for SCR, it is typically decomposed on site to ammonia, carbon dioxide (CO$_2$) and water. Regardless of the source, once the ammonia is in vapor form, it is common to dilute the ammonia stream with air to assist with transport, flow control and injection functions. Most of the earlier ammonia-based systems used anhydrous ammonia (NH$_3$) as the reducing agent as it is the most economical choice. However, due to the unique handling of NH$_3$, which has hazardous material concerns associated with both storage and transportation, there has been a trend towards utilizing an aqueous ammonia solution, which eliminates many of the hazardous concerns, or a urea [(NH$_2$)$_2$CO] system, which can be stored as a solid or mixed with water and stored in solution, to eliminate concerns even further.

When the Acid Rain Program started in the U.S. under the Clean Air Act of 1990, high NO$_x$ removals were required and SCR technology would be installed on many units burning

various fuel types. There were many lessons learned during this time which included methods for keeping the catalyst clean and free of plugging as SCR systems are typically installed upstream of the ESP that collects particulate. The most common methods to prevent plugging of the SCR include utilization of catalyst cleaning systems such as sonic horns and sootblowers, and the installation of a large ash particle screen upstream of the SCR reactor. Air cannons (also known as *ash sweepers*) with specially designed nozzles have been developed to clear ash from local areas of ash deposition on the catalyst.

Another lesson learned is that the operating temperature of the SCR must be maintained above a minimum temperature to prevent catalyst fouling from ammonium bisulfate which is formed when ammonia is injected into high sulfur content flue gas and precipitates out of the gas and onto the catalyst surface at lower temperatures. This issue has become more prominent as the allowable emissions levels have been reduced, which has resulted in the SCR being required to operate at lower loads, as well as an increasing in cycling operation, which again requires the SCR to operate at lower loads. Often, the SCR will be required to operate at boiler loads where the SCR inlet temperature falls below the minimum ammonia injection temperature, which requires a method of increasing the SCR inlet temperature. This has been most commonly accomplished by a gas-side economizer bypass, removal of economizer surface, or upgrades to the economizer water-side to allow for higher economizer exit temperatures. One such system is B&W's patented V-Temp™ system, which biases water flow through different length parallel economizer banks. As unit load is reduced, more water is biased to the shorter economizer bank, decreasing heat transfer efficiency and therefore increasing the economizer outlet temperature, allowing for a constant SCR inlet temperature through decreasing loads as shown in Figure 3.
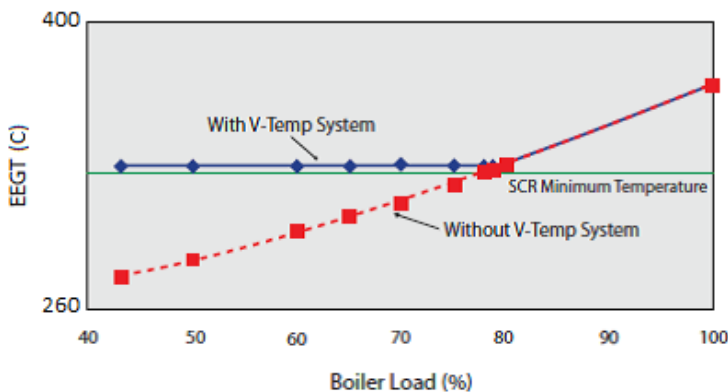

Figure 3. Predicted Economizer Exit Gas Temperature With and Without V-Temp™ System.

To maintain high levels of removal and ultra-low NO_x emissions that an SCR is capable of achieving, one of the most important factors is ensuring proper inlet ammonia-to-NO_x distribution and an even temperature profile at the inlet to the reactor vessel. As the emissions limits have been reduced, greater emphasis has

been place on computational fluid dynamics (CFD) modeling to determine the appropriate amount of flue gas mixing that needs to occur after ammonia injection to ensure achievement of the more strict ammonia-to-NO_x distribution. Additionally, the ammonia injection grids have become more refined, with an increased emphasis on tuning ability, to improve the initial ammonia dosing and limit the amount of additional mixing required (pressure loss).

Most catalysts can operate in the range of 230 to 426C but optimum performance occurs between 360 and 415C. The minimum temperature varies and is based on fuel, flue gas specifications (most notably SO_3 concentration) and catalytic formulation. Additionally, catalyst formulations have been optimized, achieving lower SO_2-to-SO_3 conversion and higher mercury oxidation, while still maintaining high NO_x emissions removal efficiencies. NO_x removal can be maintained above 90%, but requires a tightly controlled system.

Wet Flue Gas Desulfurization (FGD) for SO_2 Control

The wet FGD industry has advanced considerably from the middle of the 19th century when early attempts to remove SO_2 from flue gases involved the use of only water as the absorbing medium. The experiments focused on measurements of the solubility of SO_2 under variable pressure and temperature conditions. These early studies showed how sparingly soluble SO_2 was when compared to SO_3 which has been absorbed into water to manufacture sulfuric acid since the early 1800s and likely long before.

The first large utility scale wet FGD was built in 1931 in London, England, using water from the Thames River and passing it through multiple scrubber modules. The power plant produced about 350 MW of power and the quantity of water required for the wet FGD was significant and the plants were eventually shut down in the 1940s.

In the U.S., air pollution control started to gain traction after the Air Pollution Control Act of 1955. However it was not until the late 1960s that the U.S. began to seriously consider the need to apply stringent air pollution control to improve the ambient air quality. B&W's work with scrubbing technologies began in the pulp and paper industry although not focused on air pollution control. The pulp and paper scrubbers used a MgO solution to absorb SO_2 so B&W's first scrubber designs intended to use the same reagent for the power industry, but would also include a regeneration step. Pilot-scale demonstrations of the process proved successful for SO_2 removal, but development of the regeneration step was slow. Additionally, economic

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evaluations seemed to favor a simpler process. Therefore in 1968, B&W began to experiment with use of limestone as a suitable reagent for SO_2 scrubbing while others within the FGD industry seemed to be focused on the use of lime as the primary reagent.

B&W's pilot tests for limestone scrubbing were successful in proving that limestone could achieve adequate SO_2 removal rates for the amounts that early legislation was expected to mandate. It was during this early pilot testing that B&W learned many of the important design factors that would become a part of its performance model, including the importance of fine grinding the limestone, the level of excess stoichiometric ratio of limestone required for acceptable removals, and the optimum absorber slurry concentration that would provide greater limestone surface area for reaction and would provide sufficient liquid holdup in the gas/liquid contact zone. B&W's initial scrubber arrangement utilized on pilot plants incorporated a venturi section for PM removal with a small amount of SO_2 removal followed by a gas/liquid contact zone for the bulk of the SO_2 adsorption.

Prior to the Clean Air Amendments of 1970, some localities enacted emissions regulations for SO_2. At one such location, B&W provided the first commercial full-scale limestone scrubbing system designed to achieve local emission regulations. B&W's initial design included the venturi portion and a packing section just below the slurry recirculation headers in the gas/liquid contact zone. The arrangement of the scrubber module is shown in Figure 4.

There were many lessons learned as part of B&W's first commercial scale utility scrubber but maybe none more important than the realization that tower packing within a scrubber module was prone to plugging. This led B&W to develop a patented sieve tray design for the scrubber internals which is the cornerstone of the B&W scrubber design even today. The scrubber was
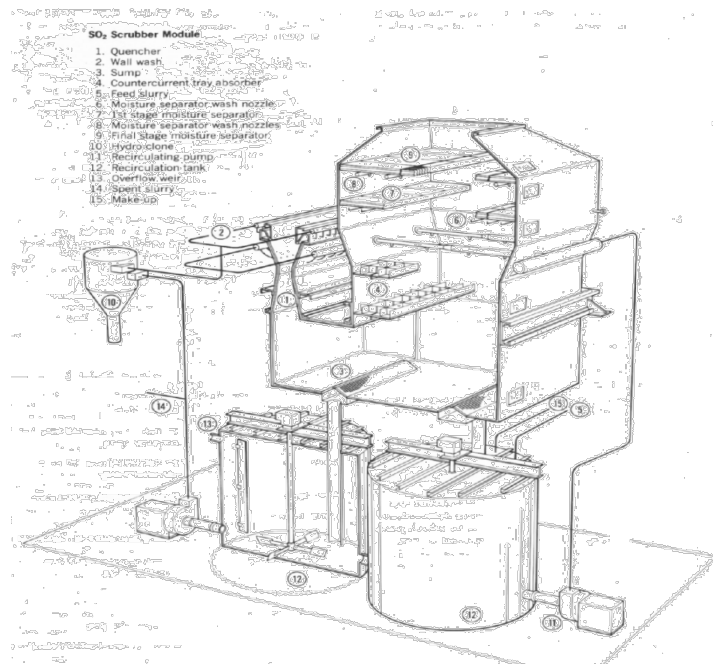

Figure 4. B&W's first commercial limestone scrubbing system.

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designed to meet 76% SO_2 removal but consumed about 4% of the boiler's electrical output. B&W provided a second scrubber which was designed for 75% SO_2 removal efficiency.

Scrubber designs after the CAA in 1970 were now to be designed to meet the first national limits on SO_2 emissions of 1.2 lb SO_2 per million Btu of heat input (0.5 mg/kJ). This pushed most of the scrubbers designed during this time period to removal efficiencies above 85% and most scrubbers were designed with a bypass system and spare modules so that individual scrubbers could be taken down for maintenance. Many aspects of scrubber design changed during this time. For example, the venturi section was no longer designed for PM removal but rather simply to quench the flue gas stream before it entered the main gas/liquid contact vessel. The reagent choice of this time period was dominated by the use of lime as the scrubbing reagent although B&W continued to provide limestone scrubbers in addition to lime scrubbers.

In 1977 the CAA was again amended to include minimum performance standards of 70% SO_2 removal for all new coal-fired power plants. The main impact to the wet FGD industry was that most scrubbers installed during this time period were designed for 90% SO_2 removal with lime continuing to be the primary reagent of choice for the industry. However, B&W was having success proving that limestone scrubbing could achieve removal levels near 95% during the 1980s. Other advancements in the scrubber industry during this time included a re-designed inlet section allowing for the removal of the external quenching section which was an area of high maintenance for utility operators. Another major advancement in the industry was a movement towards forced oxidation of the absorber slurry which had significant impact on simplifying the entire wet FGD system, especially with the removal of the large, maintenance intensive thickeners used in the dewatering system for thickening the sulfite slurries of naturally oxidized wet FGD systems. Some systems were even able to make high grade gypsum byproduct through forced oxidation that could be used by the wallboard industry, avoiding the costs associated with landfill of the stabilized sulfite byproduct. The industry also moved in a direction of higher L/G (liquid-to-gas ratio) applications and lower total pressure loss with the removal of the venturi quench section. These new innovations in wet FGD technology set the stage for another major overhaul of U.S. emissions standards.

One of the most comprehensive and impactful legislative changes in the U.S. to emissions standards came in the form of the Clean Air Act Amendments of 1990. This legislation led to the U.S. EPA's Acid Rain Program which was to take effect in 1995 and would
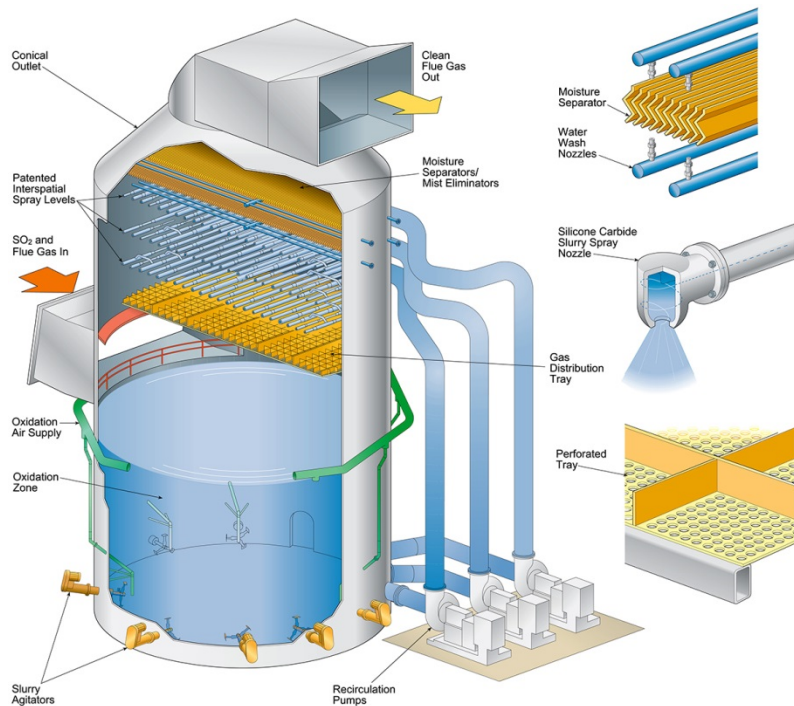
Figure 5. Modern wet FGD absorber.

have a tremendous impact on the emissions control industry. The expectations of the emissions control industry was to reduce operating and capital costs which would result in larger-sized modules capable of scrubbing the flue gases from a large boiler with a single scrubber module. (See Figure 5.) Forced oxidation was also going to be a part of all designs to change the sulfite sludge waste stream into a useful gypsum byproduct that could be sold to other industries for commercial use. This was accomplished with an air grid system internal to the wet FGD absorber reaction tank. Another major benefit of forced oxidation of the absorber slurry was the reduction in scaling problems that plagued earlier scrubber installations which had partial/natural oxidation. The expectations of the Acid Rain Program were advanced wet FGD systems that could achieve 95% SO_2 removal efficiency (although the cap and trade of SO_2 credits would push designs even further for financial gain on the credits market). Other expectations of the utility industry on wet FGD suppliers included high limestone utilization (95% or better), reliability of 99% and power consumption of the wet FGD system at less than 2% of the power station's power output.

To help achieve the mandate of the Acid Rain program much of the wet FGD auxiliary equipment also went through significant improvements. Absorber spray nozzle performance made a major impact on achieving high removal efficiencies. Nozzle design advancements during this time included the use of improved wear materials (ceramic nozzles became typical) to facilitate longer run times. Also the nozzles were capable of improving gas/liquid contact by achieving smaller droplet sizes with tangentially fed nozzles which produced a hollow cone spray pattern. These new nozzles also had larger open flow areas to prevent plugging and made internal baffles obsolete.

With larger absorber modules higher capacity absorber recirculation pumps were developed to pump slurries at a capacity of more than 11,000 m^3/hr. Improvements in the dewatering system also were significant with forced oxidation and the requirements of the commercial gypsum byproduct market of post 1990 CAA scrubbing systems. Hydrocyclones began to replace the large thickeners of the previous generation of wet FGD systems. Additionally, horizontal vacuum belt filters with cake washing systems were utilized for drying the commercial grade gypsum byproduct to a level desired by the cement and wallboard industries, while the cake wash served to wash out unwanted dissolved solids from the gypsum cake. These replaced the drum filters which dominated the filtering processes of the previous generation of scrubbing technologies.

Another important step in consistently achieving the higher removals expected of the Acid Rain Program included improvements in control valve technology and associated positioners. Additionally, instrumentation advances helped to carefully monitor the wet FGD system to optimize performance and help to avoid unplanned shutdowns that impact the reliability of the scrubber system and potentially the entire power plant. Another improvement to reliability came with lance oxidation systems which replaced oxidation air grids which were sometimes less reliable and required more maintenance.

The combination of the advancements in auxiliary equipment along with advancements in the tools used to design wet FGD systems allowed the industry to easily meet the demands of the first phase of the Acid Rain Program and achieve 95% removal prior to the second phase of the Acid Rain Program. With the second phase of the program taking effect in 2000, scrubbers were to be pushed even further on meeting even lower emissions demands as the industry began to specify systems capable of achieving upwards of 98% SO_2 removal.

Achieveing these ultra-high removal efficiencies can be quite challenging. The work required to achieve a certain SO_2 removal is measured in transfer units. The number of transfer units (NTU) required is defined below. Note that the required NTU increases exponentially as the required SO_2 removal efficiency increases.

NTU = -ln(1-fractional efficiency) or for 98% removal, NTU = -ln(1-98/100) = 3.91

The Phase 2 units are required to perform more work than the Acid Rain Program Phase 1 units that were designed from around 1993 to 2000. To illustrate, consider that the removal

efficiency required of the Phase 1 units of 95% would require 2.99 transfer units as calculated by the above equation. This indicates that the actual mass transfer work is about 30% greater for the Phase 2 units compared to the transfer units required of the Phase 1 units.

What was found to be a major factor in the design of the Acid Rain Program Phase 2 units was internal flow balancing. At such high removal efficiencies even small amounts of gas bypass would result in failure of the unit to achieve the desired performance. B&W made a number of changes to the design of the absorbers to achieve the requirements of Phase 2 but which pushed the design limits of absorber internal gas flow. Below is a summary of the design approaches for Phase 1 units that could contribute to gas flow imbalances in Phase 2 units and the innovative solutions developed by B&W scrubber design to address these issues.

1.   Increasing the nozzle density and interspatial headers – This created an area of high slurry flux in the center of the absorber and low flux at the perimeter. The result is higher gas flow around the perimeter of the absorber vessel. The combination of higher gas flow and lower slurry flux at the perimeter combine to reduce the overall SO_2 removal. New units require that the spray header and nozzle arrangements provide uniform slurry spray flux over the absorber cross section.

2.   Increasing tray pressure drop and/or using two trays – The use of a tray provides another design variable to be used in absorber design. Balance must be maintained between pressure drop across the tray, the absorber L/G and the alkalinity available in the absorption zone. The alkalinity required in the absorption zone was reviewed to ensure that the increased pressure drop of the tray, which is providing additional contact between the gas and slurry, has enough alkalinity to take advantage of this additional contact.

3.   Large diameter towers and scale-up – Testing at B&W's research center using a physical hydraulic model have indicated that there is a significant variation in slurry flux from side to side and front to back in the absorber. B&W has developed a tray design which utilizes a tray with variable open area to promote gas flow into the high spray flux areas of the tower.

4.   Spray nozzle orientation and type – Previous design standards allowed for header and nozzle configurations which were prone to channeling of the gas. At higher removal requirements, the effect of this arrangement can be significant. New absorber

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designs include nozzle types and configurations that promote robust gas flow in the center of the absorber where the highest spray flux exists.

Another important factor that needs to be considered for plants designed to meet high removal efficiencies and a commercial gypsum byproduct specification is the use of a highly reactive limestone. The use of a poorly reactive limestone creates a conflict between the SO_2 removal requirement and the gypsum quality. When a low reactivity limestone is used the rate of limestone addition will be higher to achieve the pH needed to meet the SO_2 removal specification. This higher limestone addition may result in exceeding the gypsum specification for CO_3 content or possibly other inert materials found in the limestone. Limits on limestone reactivity need to be examined for a proposed limestone to be used on a high efficiency wet FGD designed for ultra-low SO_2 emissions and meeting the requirements of a high quality gypsum byproduct.

B&W has significant experience in enhancing wet FGD system design to meet the emissions limits as imposed by tightening environmental regulations. What is especially important to note is the significant amount of experience gained through the second phase of the Acid Rain Program and pushed even further by recent NAAQS revisions and cross state air pollution transfer rules to achieve ultra-low SO_2 emissions using wet FGD technology. These lessons learned have been implemented into B&W's design standards and internal work processes to ensure scrubbers are designed to meet required emissions targets.

Mercury Control Options

In 2011 the first national mercury pollution control standards were issued by the U.S. EPA for power plants. This resulted in mercury removal requirements of 90% or greater depending upon the mercury concentration in the fuel. Controlling mercury to these levels requires an understanding of how mercury exists in the flue gas and perhaps more importantly, how the mercury is measured to report for compliance purposes. With sufficient oxidation of the mercury, a wet FGD is capable of high removal efficiencies.

Mercury, present in only trace amounts in coal, is released during the coal combustion process, and partitions in several forms in the flue gas. A small fraction of mercury will adsorb onto ash fines and other small particulates in the flue gas stream. In this phase, it is referred to as

particulate mercury. In the gaseous phase, it is referred to as vapor-phase mercury. Vapor-phase mercury, appearing in coal combustion flue gas, will be present as either elemental mercury or oxidized mercury, with proportions largely dependent on the type of coal being burned and the presence of an SCR. It has been recognized by industry experts that there is a loose empirical positive relationship between the chloride content of coal and the extent to which mercury oxidizes. A higher percentage of oxidized mercury is produced from high-chloride coal, such as eastern U.S. bituminous coals. For low-chloride coal, such as U.S. sub-bituminous and lignite coals, a higher percentage of elemental mercury is produced. The level of mercury oxidation will affect the mercury control technology required to meet mercury emissions requirements.

Additional methods that can be used to improve mercury removal in the environmental protection system of the plant includes use of a pre-combustion halogen-based fuel additive to help form more oxidized mercury, and a wet scrubber slurry additive designed to inhibit the reduction of captured oxidized mercury into elemental mercury and subsequent re-emission. Wet FGDs are effective for removing oxidized mercury.

Emissions Control System Interactions

A plant configuration for high sulfur bituminous coal includes low NO_x burners, an advanced high removal efficiency SCR NO_x removal system, dry sorbent injection, powdered activated carbon (PAC) injection, fabric filter or ESP (depending on requirements), and limestone wet FGD. A typical plant configuration is shown in Figure 6.
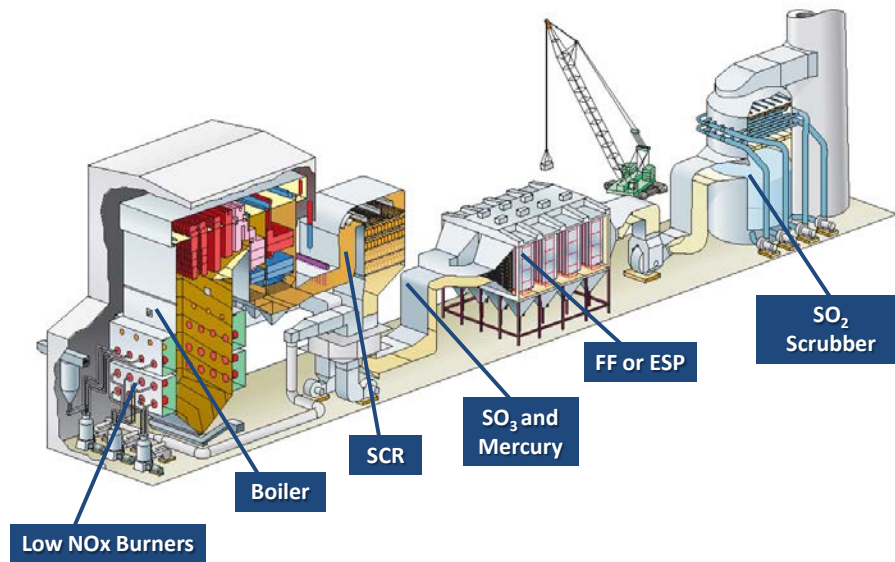
Figure 6. Typical plant configuration for high sulfur bituminous coal.

The following sections will discuss the impact of interactions between various emissions control components (SCRs and wet FGDs) on particulate matter, mercury and SO_x emissions control.

SCR impacts: Vanadium pentoxide is one of the most common ingredients in SCR catalysts. While being an active promoter of NO_x reduction in the presence of ammonia, it also is responsible for oxidizing some portion of SO_2 to SO_3 and also oxidizing elemental mercury to oxidized mercury. To fully evaluate the impacts of this phenomenon on the balance of the emissions control system, it is necessary to review the aspects of downstream capture of SO_3 and mercury across the various systems in place at a modern coal-fired power plant.

The typical power plant configuration shown in Figure 6 includes an SCR and wet FGD as part of the air pollution control system. SCR catalyst suppliers adjust the mix of active promoters, such as vanadium and molybdenum, in their formulations resulting in considerable variations in the conversion rates of SO_2 to SO_3 and mercury oxidation. A range of 0.5 to 2% of SO_2 entering the SCR system is expected to be oxidized to SO_3 and mercury oxidation over 95% can be achieved with the right combination of halogens and catalyst formulation. For air pollution control purposes the objective is to achieve high mercury oxidation with a low SO_2 to SO_3 conversion while also removing a significant amount of NO_x from the flue gas. Oxidized

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mercury will be readily removed in the wet FGD while SO_3 can be treated by various methods that will impact the particulate impact of the SO_3 portion of the flue gas.

There are several SO_3 sinks downstream of the SCR that can help reduce the overall SO_3 generation. These include:

1) A portion of the SO_3 may condense across the air heater depending upon the proximity of the gas temperature to the sulfuric acid dew point temperature. A removal rate of 20 to 70% can be expected depending upon the fly ash alkalinity. Even a modest level of alkalinity (CaO plus MgO plus Na greater than 5%) can absorb SO_3 at a high rate. The SO_3 may also be hydrolyzed to H_2SO_4 as it passes through the temperature range of the air heater.

2) The dry ESP is expected to remove a portion of the SO_3 with capture efficiency estimated to range from 10 to 30% depending on how much condenses on the ash.

3) The wet FGD will typically capture the sulfuric acid mist at a rate of 30 to 50%. Although the operating temperature in the scrubber is much lower than the acid dewpoint, the rapid quench of the flue gas converts gaseous H_2SO_4 to a mist (0.2 microns) and is difficult to remove in the wet FGD with great efficiency.

Sulfuric acid mist at the level of 5 ppmv at the stack can result in plume opacities between 20 and 30%. Efforts to reduce vapor phase concentrations of SO_3 below 5 ppmv include injection of alkali sorbents such as hydrated lime or trona (a sodium-based sorbent) ahead of the air preheater or dry ESP. Otherwise, the stacks will show a visible plume dominated by blue, sulfuric acid mist.

Impact of dry sorbent injection on ESP performance: Independent of the need to reduce SO_3 as discussed above to reduce visible emissions, it has been noted that the presence of significant amounts of SO_3 can inhibit the absorption of mercury on powdered activated carbon when utilized for in-flight capture of mercury vapors from flue gas. The recommendation by PAC suppliers has been that SO_3 levels be limited below 5 ppmv for PAC injection rates to be optimized. Results from sorbent injection of lime- and sodium-based sorbents have shown that dry ESPs lose their ability to maintain pre-injection corona power levels when lime sorbents are in use for controlling SO_3 levels below 5 ppmv, with a consequent increase in particulate emissions from dry ESPs. However, no such corona power loss has been reported when trona has been utilized as a sorbent.

Applicability of wet electrostatic precipitators in coal-fired power plants: Several power plants around the world utilize fly ash for other commercial use. For example, it is used as part of the formulation for cement or as a key ingredient in making brick. Therefore, the previously discussed options such as injecting powdered activated carbon or sorbents for SO_3 control ahead of the ESP are not an option if fly ash utilization is required. In this case, a viable technology for sulfuric acid mist as well as residual flyash is the wet electrostatic precipitator. Additionally, as PM emissions requirements become lower, the wet ESP can reduce filterable PM to levels < 3 mg/Nm^3.

Conclusions

Worldwide environmental regulations are becoming increasingly more stringent and intricate, encompassing more air emissions than ever before. Innovations that have resulted from these more stringent emissions requirements have improved and matured the control technologies. More mature product lines that meet current U.S. EPA emissions requirements have many years of lessons learned as well as research and development that can be utilized and adapted to the requirements of power plants in Asia. When a plant considers the use of air pollution control technologies, several areas of the boiler and environmental protection systems need to be evaluated to optimize the overall reduction of plant emissions.

Environmental equipment and systems utilized in a flue gas cleaning arrangement have typically been associated with the treatment of one particular pollutant. For example, an SCR system is used to reduce NO_x. However, as emissions regulations become more stringent and utilities consider the use of a wide range of fuel types as is currently happening in Asia, the interrelated effects on other pollutants of each component or system in the arrangement must be recognized. The U.S. market has experience with these interactions and a firm understanding of how to control and handle the diversity of equipment interactions that has been in practice for many years with success in meeting ultra-low emissions standards throughout the world.

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