Traditional and Emerging Air Pollutant Control for Baseload Generation Stations

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Abstract - Baseload generation stations are largely responsible for providing economical power to consumers. One factor of the power production equation is controlling the air pollutants produced by the generation process. Power producers face social, environmental, and legal air pollutants requirements that must be met in order to continue generation. Whether a producer or consumer, a better understanding of power plant air pollutants control creates increased awareness and more informed discussions. This presentation covers the basic types of air pollutants from base load generation stations, the fundamental methods of air pollutants control, and an engineering perspective on each method.

I. Introduction to Basin Electric

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

Basin Electric Power Cooperative is an electric generation and transmission cooperative that provides wholesale electricity to 138 distribution cooperatives in nine states. Headquartered in Bismarck, ND, Basin Electric operates 5,003 megawatts (MW) of generation fueled by coal, natural gas, and wind. Basin Electric also has purchase power agreements with other generation facilities in the upper Midwest, with a generation portfolio total of 5,594 MW.

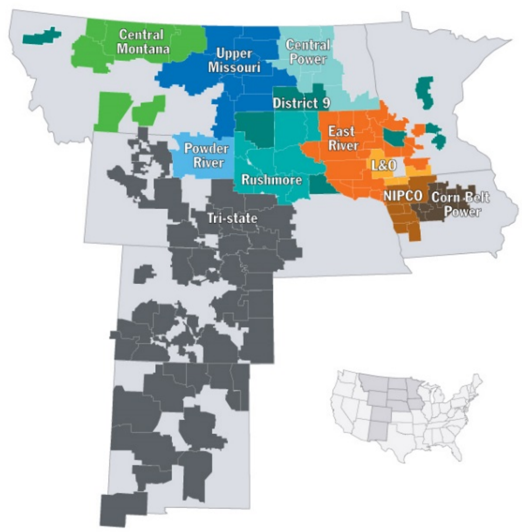


Figure 1: Basin Electric Power Cooperative service territory

Basin Electric owns and operates four coal-based power plants. Leland Olds Station (LOS) is the oldest plant in the fleet. Located in Stanton, ND, LOS is a two-unit station producing 666 MW from North Dakota lignite coal. Antelope Valley Station (AVS) is located in Beulah, ND, and is also a two-unit station producing 900 MW from North Dakota lignite coal. Laramie River Station (LRS) is the largest plant in the generation fleet. Located in Wheatland, WY, LRS is a three-unit station producing 1710 MW from Powder River Basin (PRB) sub-bituminous coal. The newest coal plant in the fleet is Dry Fork Station (DFS). Beginning commercial operation in 2011 and located in Gillette, WY, DFS is a single-unit station producing 385 MW from PRB sub-bituminous coal.

Deer Creek Station (DCS) is a natural gas combined cycle plant. Located near Brookings, SD, DCS began commercial operation in 2012 and produces 300MW. DCS is considered a baseload facility for this paper as many companies use combined cycle plants for baseload. However, Basin Electric operates DCS as an intermediate generation resource, typically running coal plants before operating DCS.

Basin Electric also operates a number of natural gas and oil-based peaking stations, as well as wind farms in North Dakota and South Dakota. Air pollutants topics for these stations are outside the scope of this paper.

II. What are air pollutants?

Air pollutants are defined as any physical, chemical, biological, radioactive substance or matter which is emitted into or otherwise enters the ambient air (1).

The EPA monitors air pollutants that are, or could be, harmful to humans. Types of air pollutants are categorized as principle air pollutants and hazardous air pollutants. The principle air pollutants (also called criteria pollutants) are known to be:

- Carbon monoxide (CO)
- Lead (Pb)
- Nitrogen dioxide (NO_2)
- Ozone (O_3)
- Sulfur dioxide (SO_2)
- Particulate matter (PM, 2.5 and 10)

Hazardous air pollutants (also known as toxic air pollutants or air toxics) are listed on the EPA website as 188 compounds that are known or suspected to cause cancer and/or birth defects in humans. Examples of air toxics are asbestos, arsenic and mercury (2).

III. How are air pollutants formed?

The type of air pollutants from a power plant are directly tied to the type of fuel being burned. The basic ingredients of coal include carbon (C), and hydrogen (H), along with lesser amounts of sulfur (S), nitrogen (N), and a few other elements such as mercury (Hg). Through the combustion process, these individual elements combine with oxygen (O) to form various oxide compounds, some of which are listed as principle air pollutants.

Natural gas is comprised mainly of carbon and hydrogen in the form of methane, ethane, propane and butane. The gas reacts with oxygen and nitrogen in the air to for nitrogen oxides and carbon oxides as the main types of air pollutants. Some sulfur can be added to the gas as an odor to help in leak detection, and this sulfur does contribute to small amounts of SO_2 air pollutants (3).

Plants must also consider pollutants not related to fuel, such as dust, sound, and water quality. Heavy equipment and material handling produce dust that can effect local visibility near the plant. Large equipment in and around the plant site produce high intensity sound for sustained periods of time. Roadways are also routinely sprayed with water to minimize particulates from blowing in the wind. Water utilized by the plant must not leave the site without proper care and treatment. While these topics are important, the scope of this paper will mainly focus on air pollutants, namely SO_2, NOx, Hg, PM, and in the future CO_2.

IV. How are air pollutants regulated?

In 1963, the United States Congress passed legislation known as the Clean Air Act. Further amendments to the Clean Air Act were passed in

1970, which put into place regulations to improve air quality in the country. Part of these regulations govern point sources of air pollutants, an example of which is a fossil-fueled power plant. This law allows the EPA to develop the National Ambient Air Quality Standards (NAAQS), which allows for national, state, and local governments to protect air quality.

Additional changes to the law in 1990 implemented an acid rain program as well as a performance-based approach to air pollutants control using the Maximum Achievable Control Technology (MACT) Standards. These new laws set the allowable air pollutants levels based on the best performing (best controlled) sources in the industry. This approach does not limit a company to use specific technology, rather sets the limits based on the best results in the industry; this allows a company to determine the best approach for their situation to meet air pollutants limits (2).

In 2011, the EPA finalized standards for mercury and other air pollutants known as the Mercury and Air Toxics Standards (MATS). A portion of this rule requires plants to reduce mercury air pollutants by 90 percent. These standards gave power plants up to four years to become compliant (4).

The air pollutants limits set by the EPA are monitored over periods of time. For example, laws can be enforced based on the average air pollutants level over a 30-day period (known as a rolling 30-day average). This allows for occasional air pollutants spikes (due to startup/shutdown or sudden load changes) to be offset by periods of low air pollutants. Continuous Emissions Monitoring Systems (CEMS) are mandated at each generation station, and must be functional for the station to avoid fines.

Air pollutants limits for fossil-fueled power plants vary based on the region and state in which the plant is located. Also, the age of the plant factors into its air pollutants limits, as newer plants will have more strict limits than older facilities. Some pollutants are governed under multiple laws, and a plant's air pollutants must meet the limits of all applicable regulations. Basin Electric's baseload generation is located in North Dakota and Wyoming, and below is a summary of the air pollutants limits for Basin Electric facilities as of 2015.

Table 1: Air pollutant limits for Basin Electric generation units

Station	NOx	SO_2
AVS 1	0.4 lb./MBtu (annual avg)	1.92 tons/hr (3-hr rolling avg)
AVS 2	0.4 lb./MBtu (annual avg)	1.92 tons/hr (3-hr rolling avg)
LOS1	0.46 lb./MBtu (annual avg)	3.46 tons/hr (3-hr rolling avg)
LOS2	0.86 lb./MBtu (annual avg)	6.83 tons/hr (3-hr rolling avg)
DFS	0.05 lb./MBtu (annual avg)	0.19 tons/hr (3-hr block avg)
LRS 1	0.5 lb./MBtu (3-hr avg)	0.64 tons/hr (2-hr block avg)
LRS 2	0.5 lb./MBtu (3-hr avg)	0.64 tons/hr (2-hr block avg)
LRS3	0.5 lb./MBtu (3-hr avg)	0.66 tons/hr (2-hr block avg)
DCS	117 tons (12-mth avg)	Based on fuel

Each plant is unique in its combination of fuel type, furnace type, and air pollutants control equipment. Also, each plant runs for different periods of time and produces varying amounts of MW. To review plant air pollutants over a given period of time, megawatt hour (Mwh) is also an important parameter to consider. Below is a table that summarizes Basin Electric's baseload generation air pollutants for 2014.

Table 2: 2014 air pollutants data for Basin Electric baseload generation

Station	NOx (lb./MBtu)	SO_2 (tons)	Mwh
AVS1	0.2	5809	2,940,648
AVS2	0.32	6975	3,293,979
LOS1	0.23	412	1,119,902
LOS2	0.37	1025	2,763,953
DFS	0.04	884	3,600,642
LRS1	0.16	2841	4,297,261
LRS2	0.16	2179	3,535,264
LRS3	0.17	2930	3,022,251
DCS	0.01	0.9	370,505

V. Compliance

Compliance of each plant with air pollutants limits is closely monitored by the Environmental Services Division at Basin Electric. If a compliance limit is exceeded, the resolution process varies depending upon the state the plant is located within. For example, North Dakota and Wyoming allow for steps of corrective action prior to issuing a fine. This gives a plant a window of time to identify and correct the issue without receiving a penalty. Other states, such as Minnesota, simply issue fines for any period of time a plant is out of compliance. Fines vary based on the type and severity of non-compliance; $25,000 per day are possible for major violations.

VI. Traditional air pollutants control methods

A. Particulate control

Particulate control methods are designed to capture particulates from the flue gas stream, prevent them from re-entering the flue gas stream, and provide means to collect and transport the particulates for disposal. Particulates are commonly grouped as bottom ash and fly ash.

Bottom ash consists of particulates that fall to the bottom of the furnace during combustion. These heavier particles have a large range in size. Particles that fall out of the coal during combustion tend to be small, similar in size to sand or pebbles. Larger particles form as slag, which is ash that sticks to the tubes inside the furnace. Based on the coal composition, ash will fuse to the water tubes at certain temperatures and if not removed via sootblowers it can build up to the size of a small car. These larger ash deposits are known as “clinkers.”

Bottom ash collection systems consist of conveyors and grinders to break the clinkers into small enough pieces to be transported to a collection area. These systems often use water to form a slurry for transport, and the slurry is brought to ash ponds where the water can be separated and reused in the process. Bottom ash is most commonly brought to a landfill for disposal.

Fly ash consists of particulates light enough to be suspended and transported in the flue gas stream. If not mitigated, this ash would follow the flue gas path up the stack.

Two basic types of particulate control methods exist for mitigating fly ash. One method is using electrostatic precipitators (ESP). An ESP consists of flue gas passing through parallel vertical plates. Between each pair of plates is an electrode charged to a negativeDC voltage. The particles pick up negative charge from the electrode and are attracted to the positively charged plates. Ash sticks to the plates until a mechanical rapper system vibrates the plates, causing the ash to fall to the bottom of the ESP. Hoppers collect the fallen ash and use air to pneumatically transport the fly ash to storage silos. Collection efficiencies of 99.9 percent are common for ESPs (5).

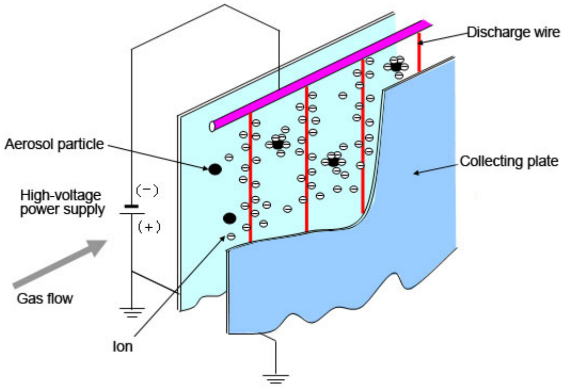


Figure 2: Schematic of electrostatic precipitator

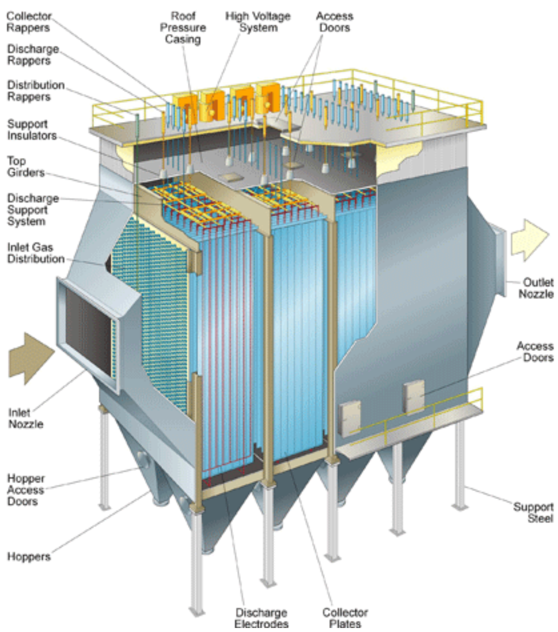


Figure 3: Typical arrangement for Electrostatic Precipitator

At LRS, the ESP is powered by a 480 VAC source that is transformed and rectified into 55 kV DC. Each ESP has 40 transformer/rectifiers. When a unit is at full load, the ESP uses about 4MW of which about 1MW is used for transformer/rectifiers and 3MW for ash collection/transport systems. The ESP is divided into four chambers, each chamber measuring approximately 100 feet long by 55 feet wide by 100 feet tall.

The other common method for controlling particulate air pollutants is using fabric filters, commonly known as a baghouse. A baghouse has similarities to a household vacuum cleaner: flue gas transports the solids to a fabric filter interface where solids are trapped on one side of the fabric while the flue gas passes through the fabric. Unlike a household vacuum, a baghouse contains thousands of fabric bags. The bags are suspended vertically and can be 30-40 feet long. Fabric filter systems are also capable of 99.9 percent particulate removal (5).

Two types of baghouses are commonly applied at power plants: reverse-air and pulse-jet. The reverse-air baghouse, which is used at AVS, is built of multiple segregated compartments. Flue gas enters the bottom and flows up through the inside of the bags. The particulates are captured on the inside of the bag as the gas passes through the bag and out the top of the house. To clean the bags, a compartment is isolated from the system and flue gas enters the top of the compartment, causing the bags to slightly compress. This compression breaks up the dust cake that has formed on the inside of the bags, and the particulate falls to the bottom of the compartment. Hoppers and conveyors then bring the particulates to a final collection system. Reverse-air baghouses put relatively low stress on the bags during cleaning, allowing for bags to be used longer (6).

At AVS, each baghouse is comprised of 28 compartments, and each compartment contains 288 bags. This results in 8,064 bags per unit. AVS presently gets five to six years of life from a bag, and the cost to replace the bags in one unit is about $2 million.

Figure 4: View of AVS2 baghouse

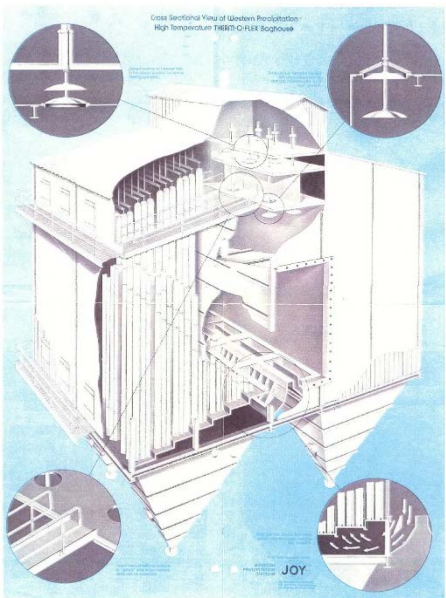


Figure 5: Expanded view of baghouse at AVS

Pulse-jet is another type of baghouse arrangement. In these systems, flue gas flows from outside the bag inward, trapping the particulates on the outside of the bag. Original designs allowed for online cleaning, where high pressure compressed air would overcome the flue gas pressure and blow the particulates off the bags. This was inherently inefficient since dust would be attracted to adjacent bags and constant upward flue gas pressure opposed gravity collection of the particulates. Newer designs allow for off-line cleaning similar to a reverse-air baghouse as well as improved on-line cleaning methods. Pulse-jet arrangements typically have smaller bags, lower installation costs and smaller footprints when compared to a reverse-air baghouse. Bag life on these systems is typically three to four years (6).

DFS utilizes a pulse-jet baghouse. This arrangement includes six compartments subdivided into 10 sections, with a total of 16,476 bags. Bags have recently been replaced at DFS, with a bag cost of $1.2 million and a total project cost of $1.6 million.

The decision on whether to use an ESP or baghouse often depends on the other air pollutants control methods utilized at the plant. If the sulfur control method is at the end of the process, then ESPs or baghouses can typically be applied. When the particulate control is last in the process, baghouses have a better residual time which allows for better final air pollutants control. ESPs are typically more sensitive to fuel characteristics, thus baghouses can be the preferred method if switching or blending of fuels is expected (6).

Particulates that are accumulated in either ESPs or baghouses are typically transported via a pneumatic conveying system to storage silos. Commonly known as fly ash, this is then transported to facilities for making concrete or to landfill for permanent storage. Ash collection systems are also in place throughout the flue gas path, including ash screens and hoppers at locations where the flue gas duct changes from horizontal to vertical direction.

A recent EPA ruling for coal combustion residuals (CCR) categorizes CCR or coal ash as solid waste, similar to household waste. The rule sets minimum design, operation, and monitor requirements for new and existing landfills and surface impoundments. Existing containment areas that are unlined or are not structurally sound will likely require retrofits or else cease from operation (7).

The final step in the air pollutants sequence is the stack. An atmospheric dispersion model is typically used to determine the height at which flue gas entering the atmosphere will disperse enough to meet the limits set by the EPA. The United States also sets maximum height limits based on Good Engineering Practice (GEP) (8). The larger stacks at Basin Electric's AVS and LRS facilities are approximately 600 feet tall with base diameters of ~60 feet and top diameters of ~30 feet.

B. Sulfur-based air pollutants control

Sulfur is a main component of coal, and during the combustion process sulfur oxidizes to form SOx compounds. Sulfur results in a blue-color plume leaving the stack and contributes to acid rain. To capture and control SOx air pollutants, various reagents are mixed with the flue gas to reduce the SOx compounds to water, carbon dioxide and gypsum byproducts.

The majority of SOx air pollutants come in the form of SO_2. One solution to lowering SO_2 air pollutants is to use or blend in coal with lower sulfur content. Since many plants have long-term contracts with certain mines, this is usually not an option. The most common solution to SO_2 control utilizes a flue gas desulfurization (FGD) unit, also known as a scrubber.

Two types of scrubbers are commonly found at large coal-based plants. The most common technology used worldwide is referred to as a wet scrubber. A wet scrubber contains large vessels known as absorber towers. Each tower has a tank at the bottom consisting of a slurry of water and a reagent, commonly processed limestone. The flue gas enters the absorber tower just above the slurry level, picking up moisture from slurry as the gas cools. The gas then flows upward through a bowl-shaped cavity where additional slurry is sprayed. As the gas rotates up through this quencher zone, the SO_2 is combined with the calcium oxide (CaO) in the reagent slurry and removed. Wet scrubbers are up to 98 percent efficient with SO_2 removal (5). For Basin Electric, wet scrubbers are applied at LOS 1 and 2 and Units 1 and 2 of LRS. The wet scrubbers recently installed at LOS cost a combined $410 million.

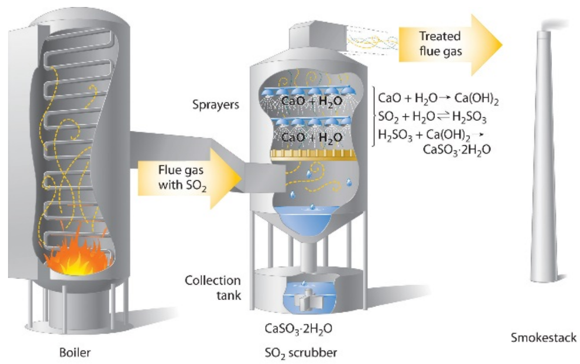


Figure 6: Internal view of generic wet scrubber

An alternative to a wet scrubber is commonly called a dry scrubber. Dry scrubbers also use a reagent slurry to mix with the flue gas, much like wet scrubbers. Unlike wet scrubbers, dry scrubbers do not have a tank of slurry inside the tower. Instead, the water and reagent (typically lime) slurry is sprayed as a very fine mist into the hot flue gas. The flue gas follows a turbulent path through the absorber, aiding to the mixture with the lime. The SO_2 reacts with the lime and forms a dry material, which is then captured at the bottom of the vessel or in a downstream particulate control device. LRS Unit 3, AVS Units 1 and 2 all have various vintages of dry scrubbers. Dry scrubbers are up to 96 percent efficient with SO_2 removal (5).

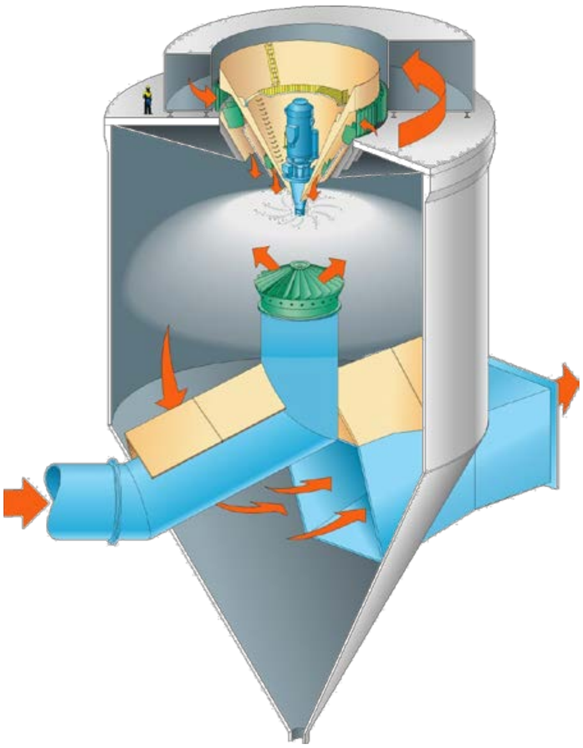


Figure 7: Artist's rendering of AVS dry scrubber

DFS uses a circulating fluidized bed scrubber. This is another type of dry scrubber that relies heavily on recycling the collected fly ash. Flue gas enters the bottom of the vessel and combines with recycled ash and hydrated lime as the mixture swirls upward. Water is used only as a mist to control temperatures of the reaction. The mixture then passes into the baghouse, where particulates are captured and reused in the process. The total cost of the scrubber and baghouse at DFS was $112 million.

Many factors enter into deciding between wet and dry scrubbers. Since dry scrubbers use less water, they may be preferable in arid climates or areas far from reliable water sources. Limestone used with wet scrubbers is typically less expensive than lime used in dry scrubbers, which enters into operating costs. Wet scrubbers result in gypsum by-products, which can be marketed to drywall manufacturers; dry scrubbers produce a less-defined byproduct which can be used in concrete mixes but is most often stored in landfills. Finally, wet scrubbers offer the best sulfur control, which may be critical for high sulfur fuels or strict limit situations (6).

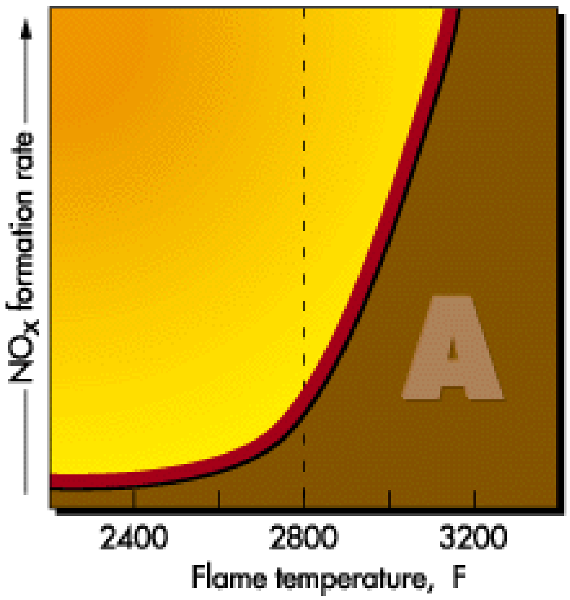
Table 3: Comparison of sulfur control methods at Basin Electric facilities

Facility	Scrubber type	Reagent	Tons per day
AVS1	Dry	Lime	150
AVS2	Dry	Lime	150
LOS1	Wet	Limestone	117
LOS2	Wet	Limestone	233
DFS	Circ. Fluid Bed Dry	Lime	60
LRS1	Wet	Limestone	40
LRS2	Wet	Limestone	40
LRS3	Dry	Lime	33.3

SO_3 is another sulfur-based air pollutant that must be monitored and mitigated. Similar to mercury control, the most common solution for SO_3 control involves injecting a dry chemical into the flue gas stream.

C. Nitrogen oxides (NOx) control

When nitrogen and oxygen atoms break from stable molecules and combine together, they form NOx particles. NOx is identified by a brown-colored plume exiting the stack and contributes to smog. As temperatures increase, NOx formation also increases, and the most rapid formation occurs at 2,800 degrees F or above (indicated by region A in the graph below). One source of NOx comes from the air in the combustion process. When the air is heated at or above 2,800 degrees F, stable N_2 and O_2 molecules are split and recombine as NOx. This accounts for about 20 percent of NOx created in combustion. The other 80 percent comes from the nitrogen content of the fuel as it is burned.



The typical first step in the control strategy is to install low NOx burners and over-fire air. The goal of this installation is simple: reduce the combustion temperatures to minimize NOx formation. The low NOx burners are designed to starve the lower combustion zones for oxygen, around 80 percent of the required amount. Over-fire air ports are then installed above the burners where the remaining air required for complete combustion is introduced. This stages the combustion and lowers the overall temperatures, instead of having a condensed, higher-temperature combustion zone lower in the furnace. Lower temperatures also allow the more aggressive sulfur and carbon atoms to attach with oxygen, resulting in the formation less NOx and more N_2 molecules. These burners and over-fire air have been or are presently being installed at all of Basin Electric's applicable coal-based stations.

Starving the combustion of necessary oxygen has practical limits. If oxygen is insufficient, CO will form rather than CO_2, and CO is a combustible compound. A build-up of CO can lead to combustion downstream in the furnace process, resulting in furnace inefficiency and combustion in undesirable locations. Plants typically have ~3 percent excess oxygen in the furnace beyond what is required for complete combustion as a means of preventing CO build-up. Proper design and commissioning of a low NOx burner and over-fire air system helps to maintain this balance.

Another complimentary method for NOx control is utilizing combustion optimization software. Paired with adequate instrumentation in the furnace, a combustion optimizer monitors the outputs of combustion and varies the fuel and air inputs for best results. For example, the LRS combustion optimizer is set to reduce NOx by adjusting the fuel/air ratio at each burner row.

The next most effective NOx control method is known as selective non-catalytic reduction (SNCR). This method injects an ammonia (NH_3)-based compound (reagent) into the furnace above the burner elevation. A typical reagent for this purpose is aqueous urea. The reagent mixes with NOx at the high temperatures within the furnace, typically at 1,400-2,000 degrees F. The atoms then combine to form nitrogen and water molecules (5).

The most effective NOx control method is known as selective catalytic reduction (SCR). This is the same technology found in modern diesel pickups. A catalyst consisting of rare earth metals allow NOx and reagent (often anhydrous ammonia) molecules to separate and recombine as nitrogen and water; this process separates more NOx than an SNCR, resulting in better air pollutants control. The catalyst chamber is often located at the economizer outlet and before the air heaters in order to utilize optimum temperatures of 680-842 degrees F for the reactions. Both SNCR and SCR solutions require some auxiliary electrical power to run air compressors and ammonia transport systems, but these loads are typically much less than those of particulate or sulfur control systems (5).

Based on the composition of the fuel, stations burning natural gas do not have particulates or sulfur as air pollutants to control. NOx is created during the combustion of natural gas, and SCRs are an effective control technique at these stations. DCS has an SCR applied in the flue gas outlet prior to the stack.

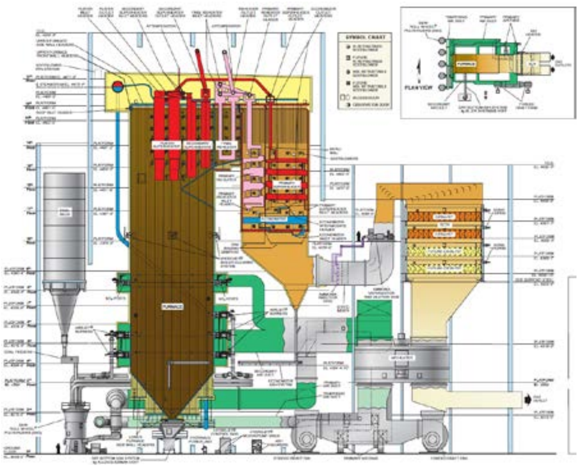


Figure 8: Cross-section view of DFS showing SCR in flue gas path

Installation of these NOx-control techniques varies greatly in cost and complexity. Combustion optimizers are the lowest hanging fruit in terms of price and installation; however, large reductions in NOx are difficult to achieve. Low NOx burners and over-fire air can often reduce NOx to acceptable levels with retrofit burners and moderate air duct modifications. SNCR installations require boiler water-wall tube modifications for reagent injection points along with process control skids to transport the reagent. The costliest and most complex NOx control method is an SCR. The weight of the catalyst requires a significant steel structure, which can be quite difficult to retrofit onto an existing unit. The type of reagent is also a factor, as urea is easier to handle but costlier while ammonia is less expensive but hazardous to handle. The reagent cost would be similar for SCR and SNCR, however the cost of replacing catalyst in an SCR every three years adds substantially to the total. Also, the SCR is a device in series with the flue gas path, adding pressure drop which may require larger induced draft (ID) and/or forced draft (FD) fans.

The values in Table 4 compare the various NOx reduction options in terms of results, cost and project duration. The reduction values are incremental, based on applying a single option at a time.

Table 4: Comparison of retrofit NOx control types

Control type	NOx reduc.	Est. cost	Project duration
Combustion optimization	15%	$0.5M	6 mths
Low NOx burners/SOFA	20-25%	$20M	12 mths
SNCR	25-40%	$10M	12 mths
SCR (new plant)	50-90%	$44M	12 mths
SCR (retrofit)	50-90%	$250M	24 mths

<u>D. Mercury control</u>

The MATS rule finalized in 2011 gave utilities up to four years to reduce Mercury and other air toxics. This rule had some impact at Basin Electric facilities, DFS already had Mercury control while AVS, LOS and LRS recently completed their control installations. The solution to reduce Mercury at these facilities was utilizing Activated Carbon Injection (ACI). ACI uses Powdered Activated Carbon (PAC), which is carbon treated with steam to create molecules with large surface areas. As this PAC is injected into the flue gas, Mercury is absorbed into the pores of the carbon and is captured in downstream particulate control devices. ACI provides Mercury reduction of up to 95 percent (5). The following photo is of an ACI silo installed at LRS.

Figure 9: ACI silo installed at LRS

VII. Emerging air pollutants control methods

One technology that has some potential for reducing NOx air pollutants is a pulsed electron beam. This technology would use an electron beam to pulse in the flue gas to break apart NOx molecules, allowing them to recombine as pure nitrogen and oxygen. While this technology has only been tried in laboratory settings, it could have significant impact on NOx reductions (9).

The biggest question facing power producers in the coming years is carbon regulation. Recently, the EPA finalized CO_2 emissions limits, which placed carbon air pollutants reduction rules on a state-by-state basis to be in compliance by 2030. The Clean Power Plan offers three building blocks for implementing the best system of carbon air pollutants reductions:

1. Improve efficiency of coal-based plants
2. Replace coal-based generation with stations using natural gas
3. Utilize more renewable energy sources

The EPA applied these building blocks to all coal and natural gas stations in the country to develop carbon air pollutants performance rates for each state.

Basin Electric is still reviewing the complexities of this 2,000-plus page Clean Power Plan, but it is already clear the rule makes assumptions that are unrealistic and has goals that are unattainable. Basin Electric owns or operates power resources in five states, so the cooperative's priority is to gain a better understanding of the full magnitude of the Clean Power Plan and what this series of dictates means for its members.

All previously discussed air pollutants topics have mature, commercially available technology for implementation. At this time, carbon control methods for generation stations are in the research and development phase. The University of North Dakota's Energy & Environmental Research Center is a leading entity in carbon capture research; for further details on this topic, please visit their website at www.undeerc.org. The following is a discussion of some types of carbon control processes under development.

Pre-combustion strategies involve changing the inputs to combustion. For example, oxy fuel combustion is an approach that separates nitrogen out of the air to use relatively pure oxygen as the air source in combustion. If natural gas is the fuel source, the resulting combustion products are only CO_2 and water. The water can be separated, leaving a stream of CO_2 for capture. Oxy fuel could also be used on a coal-based unit, but would require significant duct modifications to bring recycled flue gas back into the boiler for combustion temperature control along with sealing openings in the furnace (converting furnace from negative pressure to positive pressure). In either case, the biggest hindrance to the process is the large electrical load of the oxygen plant that is required to separate out nitrogen from the air (6).

Post-combustion strategies involve scrubbing the CO_2 from the flue gas, similar to other air pollutants control techniques. Most post-combustion processes have two stages: the first stage is an absorber that mixes the flue gas with a chemical (amines and ammonia are examples) to separate the CO_2 from the gas, and the second stage uses heat to strip the CO_2 from the chemical so the chemical can be used again in the process. The efficiency losses in this method come from needing larger ID fans due to increased pressure drops, the pump load to move material between absorber and stripper, and the steam load necessary to heat the stripping process (6).

Alstom is developing a process known as chemical looping. Under development since 1997, this high-temperature process uses chemical compounds in a regenerative loop to extract oxygen from air and extract CO_2. Chemical looping can be used for direct combustion or in a gasification role to produce synthetic gases from coal. As a retrofit option for coal-based plants, chemical looping would use the coal to produce synthetic gas or hydrogen which would then be used to fire the boiler (6). Refer to a recent Alstom presentation for an update on developments of the process (10).

The Allam Cycle is another technology under development. The Allam Cycle combines portions of the fundamental aspects of coal-based combustion with those of natural gas combustion. Natural or synthetic gas would enter a combustion chamber with oxygen produced from an oxygen plant used to remove nitrogen from the combustion air, similar to an oxy fuel system. The CO_2 produced in combustion then becomes the mechanism to drive the turbine and generator producing electricity, instead of water/steam used in typical coal-based plants. The CO_2 stays in a gaseous state throughout the process. Excess CO_2 produced from the combustion process is compressed and exits the cycle to be sequestered.

This process boasts 45-50 percent efficiencies with no carbon air pollutants. A material challenge for this process is the combination of high temperatures (2,110 degrees F) and high pressures (4,350 psi), which haven't been commercially accomplished together for turbine applications. Toshiba has designed a combustor and turbine for this application to demonstrate the process; a test site in Texas is expected to be operational in 2017.

Regardless of how carbon is captured, the next question will be what to do with it? One solution is sequestering or storing it underground. As an example, Dakota Gasification Company (DGC), a subsidiary of Basin Electric, separates CO_2 as part of synthetic natural gas processing. This CO_2 is then transported to Canadian oil fields via pipeline where it is injected into the ground for enhanced oilfield recovery. DGC produces and transports about 90 million standard cubic feet of CO_2 per day. Since 2000, DGC has captured and transported more than 30 million metric tons of CO_2.

VIII. Selecting an air pollutants control type

Fuel type and air pollutants targets will typically dictate which types of control methods are applicable. Some fuels contain higher ash or sulfur content, which may require the more robust solutions. Air pollutant mandates provided by local, state, or national agencies may also dictate the type of technology required to meet limits.

For new stations, vendors can package multiple control types together under one contract. For example, at DFS the sulfur and particulate controls were provided by a single vendor, implementing a dry-type scrubber and baghouse solution.

For existing stations, the process of selecting a control method is often determined by a best available retrofit technology (BART) study. This process is divided into the following steps:

1. Identify all available technologies
2. Eliminate technically infeasible options
3. Evaluate control effectiveness for each remaining control technology
4. Evaluate impacts and document results
5. Evaluate visibility results
6. Select BART

As an example, LOS recently went through this process for adding sulfur control. A list of seven available technologies were developed, including various types of wet and dry scrubbers, switching fuel and coal-cleaning additives. Next, a few options were eliminated since they were not feasible for the location in North Dakota or they were not commercially available. Four remaining technologies were then evaluated based on control effectiveness, cost, and visibility results. A wet scrubber was ultimately selected to provide the best commercially available results while being only incrementally more expensive than the least cost option. BART reports are available for public access through state government websites. In North Dakota, refer to the Department of Health website at www.ndhealth.gov.

IX. Summary

Many aspects of air pollutants control at power plants have an extensive history with years of experience and improvements. Traditional control methods for particulates, NOx, sulfur, and mercury continue to serve baseload generation stations around the globe. New technologies are under rapid development to meet the needs for future carbon air pollutants limits. The need for engineers to understand and develop these technologies will only continue to grow as the next generation of processes is added to the mix.

X. Special thanks

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