

ENVIRONMENTAL ISSUES – AIR EMISSIONS

Paul Durkin, P.Eng. and James McLeish, P.Eng.

**Gryphon International Engineering Services Inc.
St. Catharines, Ontario, Canada
www.gryphoneng.com**

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INTRODUCTION

Today's social and economic pressures drive boiler owners and operators to achieve better energy efficiency while maintaining or improving emissions. Rapidly evolving environmental regulations in Ontario complicate the task of assessing and implementing appropriate emissions control technologies.

This paper presents a summary of environmental guidelines, rules, and regulations presently in Ontario for boilers. Proposed new rules and regulations and those being implemented are also presented. The review focuses on recent and proposed changes which impact boiler owners and operators.

The paper also discusses the various boiler air pollutants and methods to control and minimize those pollutants.

Various fuels are consumed in boilers and these have a significant impact on the type and quantity of air emissions. Typical fuels include natural gas, distillate oil, heavy oil, coal, wood, wood waste products, municipal solid waste, and byproduct gases. The most common regulated emissions arising from these fuels include nitrogen oxides (NO_x), sulphur dioxide (SO₂), and particulate matter (PM). Many other air pollutants are also produced during boiler combustion, some depending on the fuel source and some present only in trace quantities. Other common air pollutants include carbon monoxide (CO), carbon dioxide (CO₂), volatile organic compounds (VOCs), unburned hydrocarbons (UHCs), mercury (Hg) and dioxins.

Boiler emission control technologies consist of boiler modifications that can generally be classified into three categories: pre-combustion, combustion, and post-combustion. Pre-combustion techniques minimize the impact to boiler equipment. Combustion modifications involve the fundamental boiler design process. Post-combustion control equipment generally consists of add-on equipment to clean up the stack gas before it is expelled to the environment.

TOPICS COVERED

- Present Air Emissions Requirements
 - Ontario Regulation 346 (Being replaced by Reg. 419/05, on Nov. 30, 05)
 - Ontario Regulation 127/01
 - Ontario Regulation 524/98
 - Policy Guideline A-9
- Changes in Air Emission Regulations
 - Proposed Risk Management Framework
 - Introduction of New Air Dispersion Models
 - Air Standard Setting Process
 - Approvals Process
 - National Emissions Agreements
- Particulate Control
 - Mechanical Collectors
 - Fabric Filters
 - Electrostatic Precipitators
- NO_x Control
 - Low NO_x Burners
 - Over Fire Air
 - Fuel Staging / Reburning
 - Flue Gas Recirculation
 - MobotecSystem™
 - Selective Non-Catalytic Reduction
 - Selective Catalytic Reduction
- SO₂ Control
 - Fluidized Bed Combustion
 - Wet Scrubbers
 - Dry Scrubbers
- Emissions Trading
 - Regulation 397/01
 - Emissions Trading Code
 - Ontario Emissions Trading Registry
 - NO_x Emissions Limits and Allowances
 - SO₂ Emissions Limits and Allowances
 - Emission Reduction Credits
 - Emissions Trading Mechanisms

PRESENT AIR EMISSIONS REQUIREMENTS

Ontario Regulation 346

- Regulation 346 under the Environmental Protection Act is the general regulation covering air pollution in Ontario. This regulation is being replaced by Regulation 419 on November 30, 05.
- The regulation is used by the Ministry of the Environment for limiting emissions from any facility to ensure protection of the local environment.
- Mathematical air dispersion models are used to predict a maximum ground level concentration or Point of Impingement (POI) concentrations at locations in the vicinity of facilities that emit contaminants into the air.
- These concentrations are then compared to the MOE's air quality standards to assess environmental and/or health impacts.
- The Certificate of Approval (Air) process has historically been used to assess compliance with air quality standards.

Air Emissions Standards

- O. Reg 346 specifies that a source of air pollution cannot emit a contaminant at levels that would result in a standard being exceeded at its maximal point of impingement.
- POI emissions standards based on half hour average values.
- POI emissions standards are given for 87 contaminants. The table below summarizes the most significant POI standards which boiler emissions must meet. These limits have been maintained in O. Reg 419.

Regulation 346 Air Emissions Standards - Summary of Major Contaminants

Contaminant	Concentration at Point of Impingement (Half Hour Standard)	Units
Nitrogen Oxides (NO _x)	500	Micrograms of NO _x per m ³ of air expressed as NO ₂
Sulphur Dioxide (SO ₂)	830	Micrograms of sulphur dioxide per m ³ of air
Carbon Monoxide (CO)	6000	Micrograms of carbon monoxide per m ³ of air
Suspended Particulate Matter (particulate < 44 microns in size)	100	Total micrograms of suspended particulate per m ³ of air
Mercury (Hg)	5	Total micrograms of mercury in free and combined form per m ³ of air

Air Dispersion Modelling

- The mathematical models to be utilized for air dispersion modelling given in the Appendix of Regulation 346 have been eliminated under O. Reg 419. See later section on

Changes in Air Emission Regulations for dispersion modeling requirements under O. Reg 419.

Approvals

- Proponents are required to obtain Certificates of Approval (Air) (C of A's) for sources of air and noise emissions from a large variety of sources, including the construction, alteration, or extension of any plant structure, equipment, mechanism or thing that emits a contaminant to the environment. [Section 9(1)(a) of the Environmental Protection Act]
- Approval is required for an alteration of a process or rate of production. [Section 9(1)(b) of Env'tl Protection Act]
- These calculated POI concentrations for contaminants are compared to the MOE's air emissions standards to assess compliance in the approval process.

Compliance

If non-compliance is identified, then industry has an obligation to report this to the MOE, and the necessary action should be taken.

Exemptions

Ontario Regulation 524/98 exempts the following boilers from Section 9 of the Environmental Protection Act.

- a boiler that is associated with a dwelling in a building or structure that contains one or more permanent or seasonal dwellings.
- a boiler that is used to provide comfort heating in a building if
 1. the boiler uses No. 2 fuel oil (with less than 0.5% sulphur by weight), propane, or natural gas, and
 2. the total thermal input of all fuel burning equipment that is used to provide comfort heating in the building is less than 1.5 million kJ/hr.

Monitoring and Reporting – Ontario Regulation 127/01

- Regulation 127/01 Airborne Contaminant Discharge Monitoring and Reporting became law on May 1, 2001.
- Amends O. Reg 196/01 and revokes O. Reg 227/00.
- Annual reporting on 358 contaminants.
- Smog season reporting of criteria contaminants.
- Electronic posting and public access to reports.

The objectives of Regulation 127/01 include:

- Create a comprehensive database that includes criteria air contaminants, greenhouse gases, and air toxics.
- Track the progress of air quality initiatives and commitments and to assist in the development of future environmental policy.
- Create an incentive for further emissions reductions, since all reported data would be made public.

The MOE publication entitled "Step by Step Guideline for Emission Calculation, Record Keeping and Reporting for Airborne Contaminant Discharge" dated April 2001, provides step-by-step procedures for calculating, record keeping and reporting of annual, smog season, and quarterly emissions.

Facilities are divided into 3 sectors:

- Class A Electricity Generation
- Class B Large Sources
- Class C Other Small Sources

Contaminants are divided into 3 lists:

- Table 2A 11 contaminants comprised of criteria air contaminants and greenhouse gases
- Table 2B 79 contaminants with lower reporting thresholds
- Table 2C 268 contaminants which are common to the National Pollutant Registry list and have the same reporting criteria as NPRI

O. Reg 127/01 Release Thresholds – Table 2A

Contaminant	Release Threshold (kg/yr)
Nitrogen Oxides (expressed as NO)	2,700
Sulphur Dioxide	20,000
Particulate Matter	20,000
PM ₁₀ (PM<10µm)	500
PM _{2.5} (PM<2.5µm)	300
Volatile Organic Compounds	10,000
Carbon Dioxide	100,000,000
Carbon Monoxide	20,000
HFC-134A	10
Methane	5,000,000
Nitrous Oxide	2,700

- *Annual reporting* is required for the contaminants falling in the three categories if the release threshold is exceeded.
- *Smog season reporting* (May to September) is required for criteria air contaminants, in addition to annual reporting.
- *Quarterly reporting* is required for NO_x and SO₂, which are of particular significance to smog and acid rain.
- Phase 1 – began May 2001 – Class A and B must report.
- Phase 2 – began Jan. 2002 – Class, A, B, & C must report.

The reporting thresholds for contaminants in Table 2A apply for facilities with boilers with any of the following:

- i. The facility uses coal, refuse, wood, or waste oil as fuel at any time.
- ii. The facility has a name plate capacity of greater than 3 million Btu/hr.

A university or college of applied arts and technology, office building, hotel, shopping centre, or similar commercial building only needs to monitor and report SO₂, NO_x, and HFC-134a.

An emissions monitoring system is required for monitoring NO_x and SO_x for facilities with a discharge unit with a nameplate capacity of more than 73 MW total energy input. An emission monitoring system can mean CEMS, PEM, source testing, mass balance, site specific emission factors, published emission factors, mission estimation models, or other methods approved by the MOE.

Guideline A-9 NO_x Emissions from Boilers and Heaters

Policy Guideline A-9 falls under the legislative authority of the Environmental Protection Act and Ontario Regulation 346 / 419.

- This Policy Guideline adopts the National Emission Guideline for Commercial/Industrial Boilers Heaters, approved by the Canadian Council of Ministers of the Environment in March 1998 (CCME Guideline).
- This Policy Guideline indicates how the Ministry will interpret and apply the CCME Guideline.
- Specifies limits for NO_x emissions for *new or modified* fossil-fuel boilers and heaters which have a fuel energy input greater than 10 million Btu/ hr (10.5 GJ/hr).
- In order to obtain a Cof A, the owner must satisfy the MOE that the new or modified boiler or heater will emit NO_x within the limits of the CCME guideline.
- The owner must present to the MOE a statement signed by a Professional Engineer verifying that the new or modified boiler or heater will emit NO_x within the specified limits.

Acceptable Proof of Compliance:

1. Certification records for packaged boilers and heaters which are already certified as low-NO_x which meet the emission limits of Guideline A-9.
2. The applicant provides sufficient supporting information showing that an identical boiler operating in another location in an identical situation meets the A-9 limits.
3. For new, unique equipment which has not been tested or certified previously, the applicant must provide sufficient supporting information to show that the equipment emission rate will be within the limits of Guideline A-9.

- Guideline A-9 does not apply to boilers that are fired with a standby fuel (less than 500 hours per year).
- Emissions limits do not apply to certain industrial boilers listed in the CCME Guideline as follows:

Coal-fired Boilers & Heaters	Blast Furnace Stoves
Wood-fired Boilers & Heaters	Reheat Furnaces
Byproduct Fuel Boilers	Coke Ovens
Chemical Recovery Boilers	Pyrolysis Heaters
Steam Reformer Heaters	Steam Cracking Htrs

Policy Guideline A-9 NO_x Emissions Limits (as NO₂)

Boiler Fuel	Boiler Capacity	
	10.5 – 105 GJ/h (10 – 100 MMBtu/h)	> 105 GJ/h (>100 MMBtu/h)
Gaseous Fuel	26 g/GJ 49.6 ppmvd@3%O ₂	40 g/GJ 76.3 ppmvd@3%O ₂
Distillate Oil	40 g/GJ 72.3 ppmvd@3%O ₂	50 g/GJ 90.4 ppmvd@3%O ₂
Residual Oil (<0.35% N)	90 g/GJ 162.7 ppmvd@3%O ₂	90 g/GJ 162.7 ppmvd@3%O ₂
Residual Oil (≥0.35% N)	110 g/GJ 198.9 ppmvd@3%O ₂	125 g/GJ 226.0 ppmvd@3%O ₂

CHANGES IN AIR EMISSION REGULATIONS

- In 2001, Ontario released a discussion paper entitled “A Proposed Risk Management Framework for the Air Standard Setting Process in Ontario – Implementation of Ontario’s new or revised air quality standards relating to Ontario Regulation 346 (under the Environmental Protection Act) as amended”.
- The proposal was based on a risk management framework for setting standards.
- In principle, all air quality limits would be health-based and would come into effect right away. If industry shows cost or technical grounds, they could have four years to comply with new limits. Evidence of major economic hardship or technical impossibility would have to be produced to justify longer delays or less stringent limits, and all such evidence would be posted for public review.

Three program areas are linked together in the new regulations.

1. Introduction of New Air Dispersion Models

- Phased out Reg 346 dispersion models.
- Replaced with a suite of US EPA air dispersion models AERMOD, ISCST3, ISCST Prime and SCREEN3. These are the most up-to-date scientific tools available.
- Could change compliance status for some facilities.
- MOE plan was to introduce the new models over a period of 3 to 5. During the transition period, a proponent was allowed to use either the existing Reg. 346 model or the USEPA models to support an application for a Certificate of Approval (CofA). After the transition period, the Reg. 346 model is being retired and the new models used exclusively under Reg. 419 as of November 30, 05.

Comparison of Air Dispersion Models

Regulation 346 Model	AERMOD, ISCST, ISCST Prime, SCREEN3
Incorporates simplifying assumptions with regards to the effects of building size and height on dispersion characteristics.	Use complex algorithms to simulate effects of building geometry on dispersion characteristics.
Can assess single or multiple stack scenarios. Very simple assumptions are made concerning virtual sources that do not consider the actual location of the source	SCREEN3 can only model one source at a time. The ISCST Prime and AERMOD models allow the modeling of multiple stacks and sources. The location and discharge properties of each emission source are taken into consideration in the ISCST Prime and AERMOD models.
Considers only two atmospheric stability classes and does not take into account actual	AERMOD and ISC Prime are designed for the use of actual hourly meteorological data. SCREEN3 model uses

meteorological data.	a defined meteorological data set that generally provides a conservative estimate of impact. ISC Prime can also be used with a defined screening data set.
There is widespread consensus that the Reg. 346 model does not accurately represent the potential impact of a facility.	There is general consensus that the maximum concentrations predicted by the model are representative.

2. Air Standard Setting Process

- The MOE air standard setting process is based on setting air quality levels based purely on human health.
- Takes cost and feasibility into account primarily in the schedule for achieving those limits, not in what the limits should be.
- Adopts scientifically defensible effects-based air quality standards.
- AAQC (Ambient Air Quality Criteria) are set at a level where there is no adverse effect on people or the environment. AAQCs are not enforceable in themselves because many different sources of pollutants contribute to the overall air quality. POI standards are derived from AAQCs using appropriate conversion factors.
- New dispersion models provide the ability to model concentrations using appropriate averaging times to provide a more representative assessment of health and environmental impacts from a facility. For example, the effects-based averaging time for many health-based air quality standards is over a 24 hour period. However, with existing O. Reg 346 models, assessment can only be done using the maximum ½ hour emission rate and comparing to a conservative screening level concentration at a point of impingement. The new dispersion models allow for the use of emission rates for actual operating times to assess compliance with a 24 hour effects-based air quality standard.
- Tables in Reg 346 are replaced with new tables which include air standard as well as averaging time to be used.

3. Approvals Process

- Comprehensive Site-Wide Certificate-of-Approval to be available.
- Comprehensive Site-Wide CofA provides operational flexibility to proponents by allowing process changes without the need for further amendments to a CofA so long as a facility can demonstrate ongoing compliance with the air quality standards.
- Shifts the focus from equipment or stack-specific reviews to comprehensive, site-wide compliance with the air standards.
- Advantage for industry – reduces administrative costs and time delays in making process changes.

- Advantage to MOE and public – more effective protection of environment through comprehensive technical reviews and compliance auditing.

New actions for facilities under risk management Framework for air standards:

- Assess compliance with proposed effects-based standard.
- Develop and maintain a current site-wide emissions inventory.
- Complete a site-wide assessment of emissions and predicted impacts relative to the proposed new or revised air standards. See MOE document “Procedure for Preparing an Emission Summary and Dispersion Modelling Report”.
- If the emission summary and dispersion modeling report shows compliance with the proposed new or revised air quality standards, then a facility is eligible to obtain a Comprehensive Site-Wide CofA.

Other Significant Emissions Agreements

Kyoto Protocol – CO₂ Emissions Limits

Under the Kyoto Protocol, Canada is committed to reducing its greenhouse gas emissions by 6% below 1990 levels between 2008 and 2012. The Federal Government published its implementation plan in April 2005 - Moving Forward on Climate Change: A Plan for Honouring Our Kyoto Commitment. Ontario has offered the document “Air Quality and Climate Change – Insights, Opportunities, Solutions” as part of Canada’s plan to address climate change.

The Kyoto protocol includes three mechanisms for Annex I countries:

- Clean Development Mechanism – gain credits for investing in emission reduction projects in 3rd world countries.
- Joint Implementation – investing in projects in Annex I countries with “economies in transition. Annex I countries include countries such as Russia and Eastern European countries as well as 1st world countries such as Canada, Japan, European Union. The United States and Australia are two notable exceptions from the Kyoto agreement.
- Emissions Trading – purchasing and selling credits between Annex I countries.

Mercury Emissions Limits

Under the Canada-Wide Standards (CWS) process, Ontario has set mercury release limits for incinerators and is currently developing mercury standards for coal-fired power generation. The plan would result in over 50% reduction in mercury emissions. However, it includes zero mercury emissions from coal-fired plants in Ontario after 2009, when the coal plants are suppose to be closed.

Ozone Annex

Canada’s federal government negotiated the ‘Ozone Annex’ with the U.S., which was signed on December 7, 2000. This agreement targets the key smog precursor pollutants nitrogen oxides (NO_x) and volatile organic compounds (VOCs). The Ontario NO_x emission cap in Regulation 397/01 is based on Ozone Annex requirements.

Countdown Acid Rain Program

The Ontario SO₂ emission cap in Regulation 397/01 is based on requirements of the Countdown Acid Rain Program.

BOILER EMISSION CONTROL TECHNOLOGIES

Particulate Control

Particulate consists of solid and liquid matter which is suspended in the flue gas. Particle sizes from combustion sources are in the range 1 to 100 µm.

The harmful effects of particulate emissions include impaired visibility, soiling of surrounding areas, and human respiratory problems.

Particulate emissions arise from:

- 1) noncombustible ash-forming mineral matter in the fuel which is released during the combustion process.
- 2) incomplete combustion of the fuel which results in unburned carbon particles.

Except for natural gas, all other fossil fuels contain some quantity of ash or non-combustibles.

Particulate control equipment removes particulate from the flue gas, keeps the particulate from re-entering the gas, and discharges the collected material. The selection and design of particulate control equipment is closely tied to the type of firing system.

Particulate control system performance is characterized by the removal efficiency which is calculated as:

$$\text{Removal Efficiency} = \frac{\text{Inlet Dust Loading} - \text{Outlet Dust Loading}}{\text{Inlet Dust Loading}} \times 100\%$$

Coal Cleaning

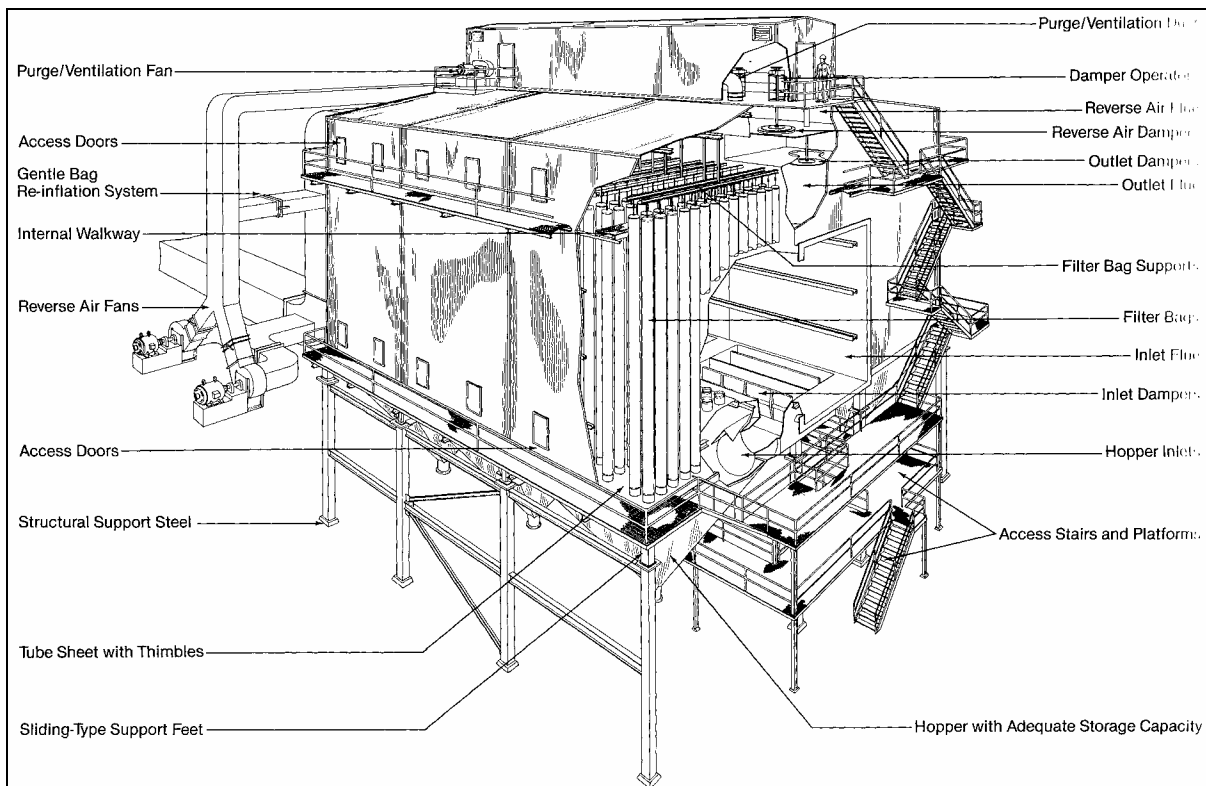
Coal is physically cleaned to reduce mineral matter.

Mechanical Collectors

- Often called cyclones or multicyclones.
- Used on small boilers with less stringent particulate emissions limits.
- Low cost, simple, compact, rugged.
- Collection efficiency varies between 10% and 95% depending on particle size.
- Used to separate large particles from a flue gas stream.
- The cyclonic flow of gas within the collector and the centrifugal force on the particulate drive the particulate out of the flue gas.
- Hoppers below the cyclones collect the particulate and feed an ash removal system.
- Most effective on particles larger than 10 microns.
- Can no longer be used as the primary control device, due to stricter regulations.

Fabric Filters

- Commonly referred to as baghouses.
- Various designs – reverse air, shake/deflate, pulse jet
- Collection efficiency >99.8%.
- High pressure drop.
- Collects the dry particulate matter as the flue gas passes through the filter material.
- The fabric filter is comprised of a multiple compartment enclosure with each compartment containing up to several



Baghouse for Particulate Control (from Ref. [1])

thousand long, vertically supported small diameter fabric bags.

- The individual bags are closed at one end and connected to a tubesheet at the other end to permit the gas to pass through the bag assembly.
- The layer of dust accumulating on the bag is called the dustcake.
- The major forces causing the collection are impingement and dustcake sieving.
- Once formed, the dustcake provides most of the filtration.
- As the dustcake builds and the flue gas pressure drop increases, the bags must be cleaned.
- Bag cleaning methods distinguish the fabric filter types.
- The most common bag material is woven fiberglass. Synthetic materials are also used which provide better abrasion resistance and resistance to acid attack.
- Well designed filters achieve greater than 99.9% particulate removal.
- When the dustcake has high alkalinity, it can be used to remove other flue gas constituents such as sulphur dioxide.
- Each filter compartment has a hopper to collect the dislodged particulate and to channel its flow to the ash removal system.
- The fabric filter is a metal encased structure with individual bag compartments.

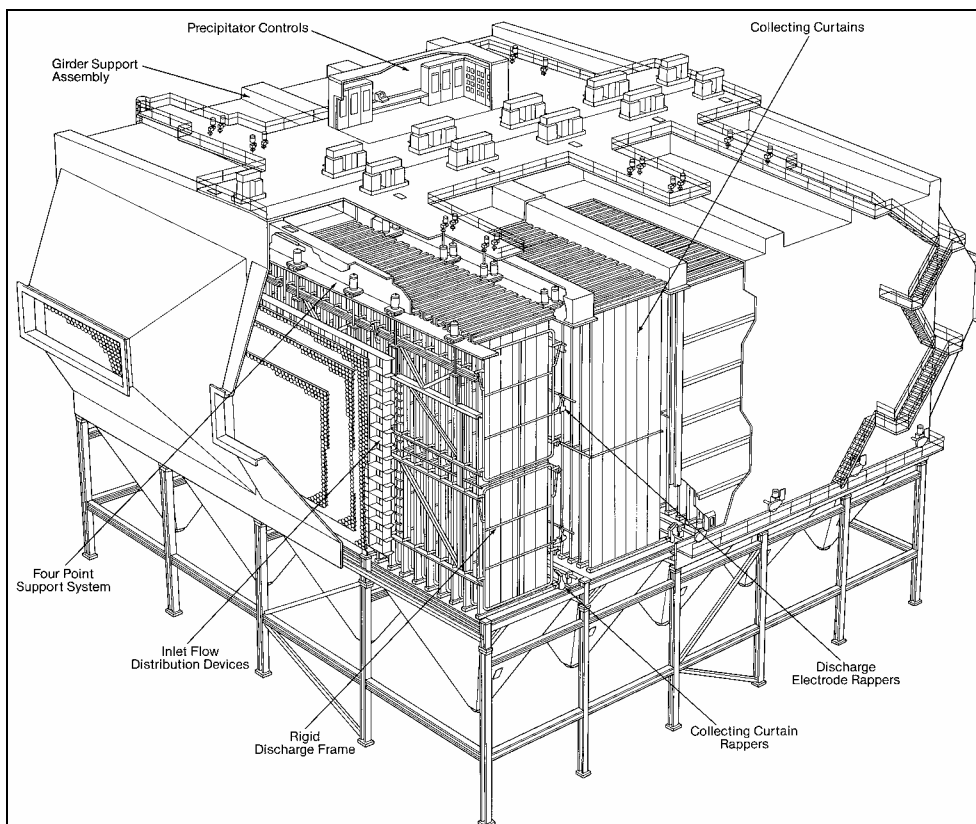
Electrostatic Precipitators

- Collection efficiency >99.8%.
- Very low pressure drop.
- Performance is sensitive to flyash loading, ash resistivity, and coal sulfur content.

- Overall, lower power usage than fabric filters.
- Less sensitive than fabric filters to plant upsets because materials are not as sensitive to maximum temperatures.

ESP Operation

- An ESP electrically charges the ash particles in the flue gas to collect and remove them.
- Comprised of a series of vertical plates through which the flue gas passes. The collecting plates are typically grounded and are the positive electrode components.
- Charging electrodes are centered between the plates which provide the electric field.
- As the flue gas passes through the electric field, the particulate takes on a negative charge.
- The negatively charged particles are attracted toward the grounded collection plates and migrate across the gas flow.
- The particulate accumulates on the collection plates and forms an ash layer.
- The ash layer is periodically removed in sheets by rapping. The sheeting is important to prevent re-entrainment of particles.
- Rapping consists of suddenly striking the collection surface to dislodge the ash.
- A separate rapping system is used to clean the discharge electrodes, which some charged particles also attach to.
- The dislodged particulate falls from the collection surfaces into hoppers.
- The hoppers are discharged into the ash conveying system.



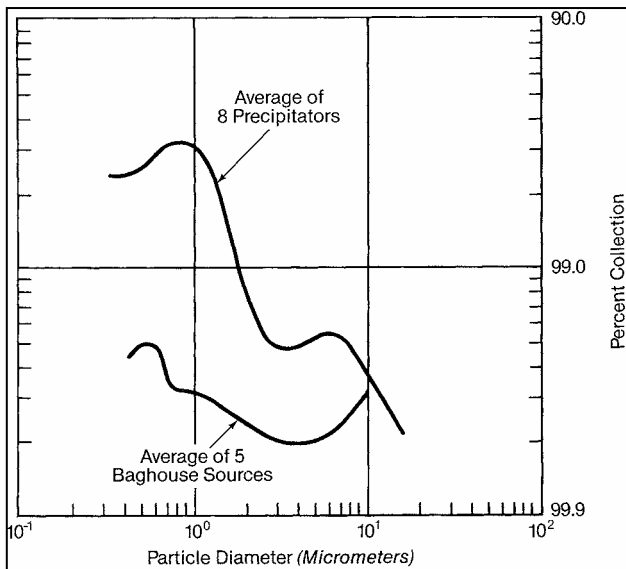
Electrostatic Precipitator (from Ref. [1])

ESP Sizing Factors and Performance

- Sizing procedure determines the amount of collection surface required to meet the specified performance or particulate collection efficiency.
- Collection surface area required depends on flue gas flow rate, migration velocity, and ESP removal efficiency required.
- Migration velocity is the theoretical average velocity at which the charged particles travel toward the collection surface. This velocity depends on how easily the particulate is charged, and is affected by fuel and ash characteristics, operating conditions, and gas flow distribution.
- Fuel and ash constituents which reduce resistivity of the ash are favorable, including moisture, sulfur, sodium, and potassium. Calcium and magnesium hamper ash collection.
- Flue gas temperature has a direct effect on flue gas resistivity and flue gas volume flow rate.
- ESP is less efficient for smaller particles (less than 2 microns) than for larger ones.
- Uniform flow is typically achieved by installing distribution devices in the flue transition sections immediately upstream and downstream of the ESP.

ESP Applications

- Utility coal fired boilers.
- Industrial non-coal fired units including municipal refuse incinerators, wood, bark, and oil fired boilers.
- Pulp and paper power boilers and recovery boilers.



Particulate Collection Efficiency (from Ref [1])

Wet Scrubbers

- Venturi type wet scrubber is used to transfer suspended particulate from the gas to the liquid, by intimate contact between a gas stream and the scrubber liquid.
- High gas pressure drop.
- Infrequently used as the primary collection device – wet scrubbers are in series with a high efficiency collector for control of acid emissions on most coal fired applications.

Nitrogen Oxides Control

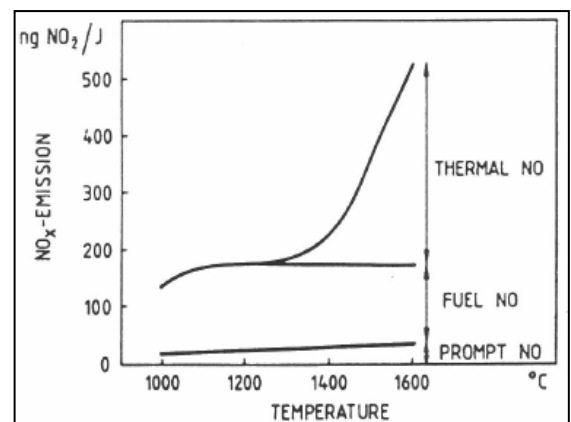
NO_x refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO₂) and trace quantities of other species generated during combustion.

NO_x is formed during combustion due to high temperatures and the availability of oxygen and nitrogen from both air and fuel. NO_x emissions from fired processes are typically 90 to 95% NO with the balance being NO₂. Once the flue gas leaves the stack, the bulk of the NO is eventually oxidized at low temperatures in the atmosphere to form NO₂. It is the NO₂ in the flue gas which creates the brownish plume often seen in a power plant stack discharge.

In the atmosphere NO₂ reacts with sunlight and hydrocarbon radicals to produce photochemical smog and acid rain constituents.

NO Formation Mechanisms

1. **Thermal NO** - High temperature oxidation of nitrogen found in the combustion air, as postulated by Zeldovich. The traditional factors leading to complete combustion all tend to increase the rate of thermal NO_x formation (high temperature, long residence time at high temperature, and high turbulence).
2. **Fuel NO** – Nitrogen in fuel is much more reactive than nitrogen in air. As the fuel is pyrolyzed, part of its nitrogen is released and forms gaseous HCN and NH₃ compounds. These compounds are further oxidized to nitric oxide (fuel NO). During combustion, approximately 20 to 30% of fuel bound nitrogen is converted to NO. Conversion of fuel-bound nitrogen to NO_x is strongly dependent on the fuel/air stoichiometry, but is relatively independent of variations in combustion zone temperature. Fuel NO contributes approximately 50% of NO_x emissions when firing residual oil, and 80% when firing coal.
3. **Prompt NO** – The rapid reaction of fuel bound nitrogen with hydrocarbon fractions in the vicinity of the flame zone. The reaction occurs under fuel rich conditions very early during the combustion process. Prompt NO_x formation normally has a weak temperature dependence, but becomes stronger under fuel rich conditions. Modern burners are designed to reduce peak flame temperatures by controlling the rate of fuel and air mixing, and initiating combustion under fuel rich conditions.



NO Formation Mechanisms (from Ref. [2])

A. Precombustion Control (Fuel Switching)

Nitrogen constituents in the fuel cannot be easily reduced or removed.

An option for reducing NO_x levels is to switch to a fuel with lower nitrogen content. Coal combustion generally produces highest NO_x emissions, oil combustion generates less NO_x, and gas firing produces the least NO_x in boilers. When firing oil fuels, a reduction in fuel nitrogen results in reduced NO_x generation.

B. Combustion Modification

Combustion modifications control NO_x by suppressing thermal NO and fuel NO. With natural gas and oil fuel, thermal NO is the only component that can be practically controlled, due to the low levels of fuel nitrogen.

NO_x formation is promoted by high peak flame temperatures and excess available oxygen, due to rapid mixing of air and fuel.

Mechanisms for controlling NO_x involve:

- 1.Reducing peak flame temperatures.
- 2.Reducing oxygen availability in the initial combustion zone.
- 3.Controlling the rate of fuel-air mixing.

1. Reduce Peak Flame Temperature

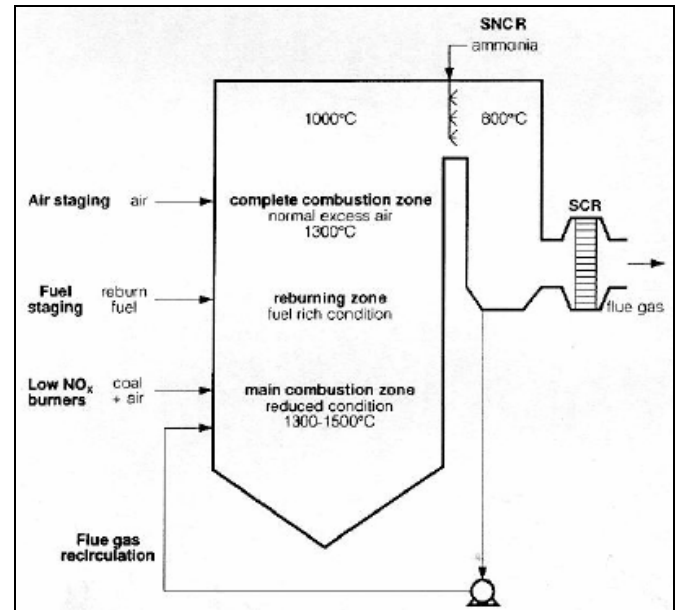
- i. Water or Steam Injection – not widely applied due to potential efficiency penalties, safety, and burner control problems.
- ii. **Flue Gas Recirculation (FGR)** – recirculate a portion of flue gas to the burner zone.
- iii. Reducing Air Preheat Temperature – severe energy penalties and usually not considered.

2.**Minimize Excess Oxygen** - the beneficial effect of lower excess O₂ on NO is partially offset by an increase in thermal NO_x due to higher peak flame temperature due to lower gas volume.

- i. Oxygen trim or low excess air (LEA) – may be impractical due to increased flame length and increased CO.
- ii. Staged Combustion Air (SCA) - delaying mixing of fuel and air – take burners out of service or bias the fuel flow to selected burners.
- iii. Reduce boiler firing rate – often not considered due to reduced steam generation capacity.

3.**Control the Rate of Fuel-Air Mixing** - fuel NO is minimized by suppressing the amount of air below that required for complete combustion.

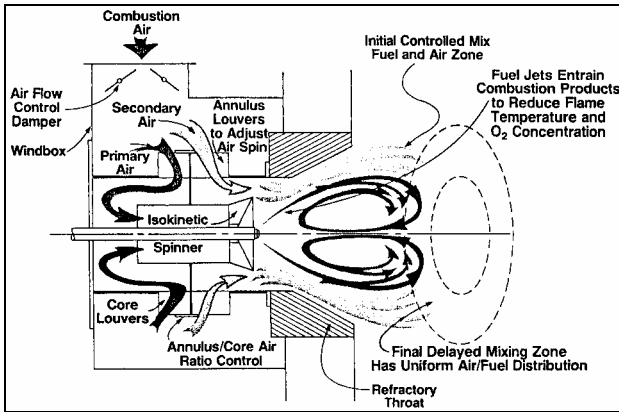
- i. Air Staging - accomplish by internally staged air burner (**Low NO_x Burner**) or **Over Fire Air (OFA)**.
- ii. Fuel Staging (**Reburning**) – inject a portion of the fuel downstream of the main combustion zone – hydrocarbon radicals created by reburning the fuel will reduce NO_x emissions from the primary fuel.



Boiler Combustion Zones (from Ref. [2])

Low NO_x Burners (LNB)

- Low NO_x burners (LNB) are designed to delay and control the mixing of fuel and air in the main combustion zone.
- Lower combustion temperatures and reducing zones are created by LNBs which lower thermal and fuel NO_x.
- Secondary air controls the flame length.
- LNBs can be divided into two different general technologies:
 - i) **Delayed Combustion** LNBs are designed to delay fuel/air mixing in the primary combustion zone by reducing flame turbulence. This provides for an initial, fuel-rich combustion of lower flame temperatures. The long flame duration inhibits the formation of thermal NO_x, while the fuel-rich condition of the primary combustion inhibits the formation of fuel NO_x.
 - ii) **Internally Staged** LNBs create stratified, dual combustion zones consisting of a fuel-rich zone and a fuel-lean zone. The fuel-rich zone inhibits the formation of fuel NO_x, and the fuel-lean zone provides for complete combustion at a lower temperature.
- Fouling is promoted in many low NO_x burner designs because the burner register relies on mechanical devices, such as bluff bodies and/or spinner vane assemblies located near the atomizer tip, to either stabilize the flame or stage air introduction into the root of the flame.
- LNBs can be combined with other treatment controls to further reduce NO_x emissions.
- Various manufacturers have developed LNB technologies.
- A typical low NO_x burner is shown in the following figure.



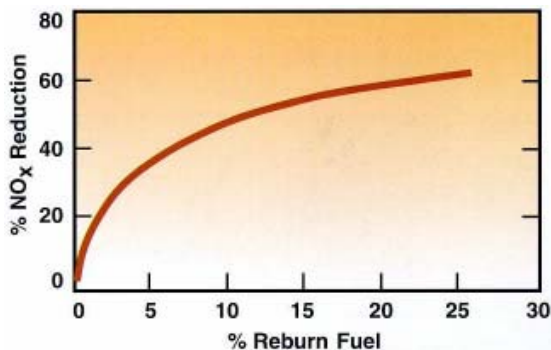
Low NOx Burner - Coen Type DAF (from Ref. [3])

Over Fire Air (OFA)

- OFA systems divert a percentage of the combustion air (typically between 10% and 30%) to an elevation above the burner zone.
- The lower rows of burners are operated under sub-stoichiometric conditions and the remaining air supplied in the middle or top of the furnace.
- Formation of fuel NO is inhibited by limiting the amount of O₂ available in the early stages of combustion, where most of the fuel nitrogen gets released during devolatilization.
- A lesser reduction in Thermal NO is also achieved by a marginal decrease in combustion flame temperature.
- Successful implementation of air staging requires careful monitoring of the unburned emission components.
- NO reduction depends on type of fuel – 10 to 50%.

Fuel Staging / Reburning

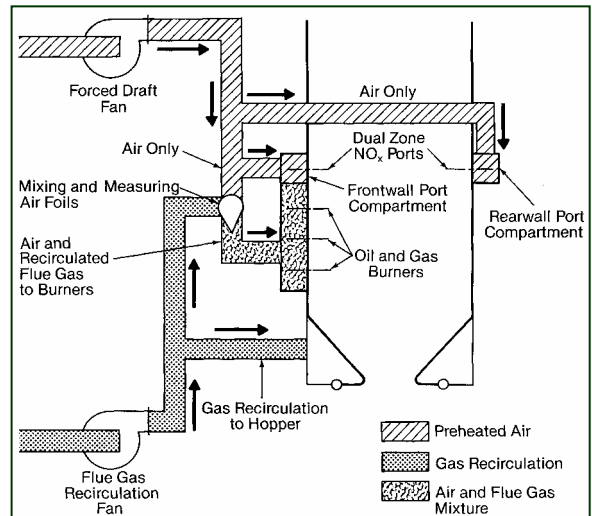
- Utilize fuel to reduce nitric oxide that has already formed to molecular nitrogen.
- Three stages:
 - a. Main Combustion Stage – Fuel burned with excess air.
 - b. Secondary Stage - A secondary fuel such as natural gas is injected corresponding to 10-20% of the primary fuel. The NO formed in the main combustion stage is reduced to molecular nitrogen in a complicated chain reaction initiated by hydrocarbon radicals originating from the secondary fuel.
 - c. Final Combustion Zone – Air is added to complete the combustion of the secondary fuel. Nitrogen compounds present (NO, HCN, NH₃) are oxidized back to NO and/or N₂. The final combustion stage has the advantage of a low temperature (<1000°C) for formation of molecular nitrogen.



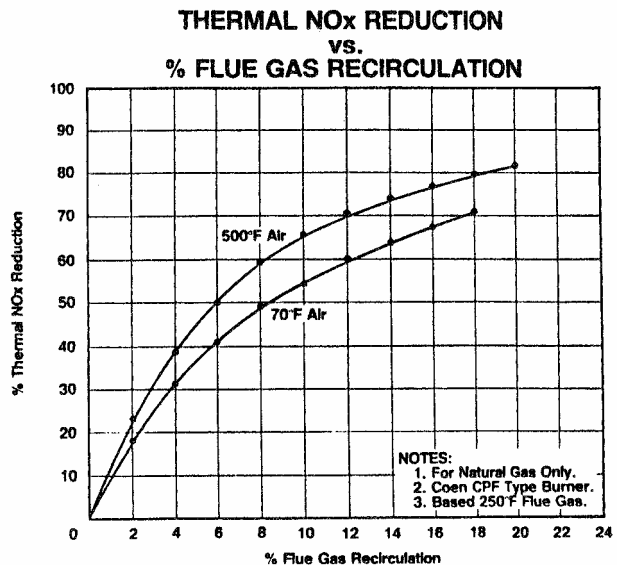
- Fuel staging can be applied to either a burner or the entire furnace. For a burner, the same fuel is used as the primary and secondary fuel.
- NO reduction of 30 to 70%.
- Problems – increased unburned flue gas components, increased corrosion and fouling of furnace walls.

Flue Gas Recirculation (FGR)

- A portion of the flue gas is recirculated back to the burner.
- Burner peak flame temperatures are lowered and Thermal NO is significantly reduced.
- Used on natural gas and oil fuelled boilers.
- Air foils typically used to mix recirculated flue gas with the combustion air.
- Burner stability and O₂ concentration are limiting factors.
- Expense of gas recirculation fans, controls & instruments.
- Usually accompanied by installation of overfire air ports.



Flue Gas Recirculation System (from Ref [1])



Flue Gas Recirculation Low NOx System for Oil and Gas Firing (from Ref. [2])

MobotechSystem™

A new 3-step system that is based on the good intermixing of combustion gases to achieve better combustion, high efficiency, and low emissions.

1. ROFA (Rotating Opposed Fire Air) System

- 2nd generation overfire air system.
- Reduces NOx by improving combustion via the injection of high velocity overfire air into the boiler at predetermined points to create great turbulence in the boiler and better mixing of the fuel and air through the whole furnace volume.
- Rotating OverFire Air creates a horizontal rotation in the flow of air and combustion gases inside the furnace. This rotation increases the flue gas velocity and allows for delayed combustion. It also assures for good admixture of air without increasing CO levels. As a result, the furnace temperature is reduced and the “hot spots”, where most of the thermal NOx is generated, are minimized.
- Irregular fuel supply or poor mixture of combustion air can create zones with too high or too low oxygen levels, resulting in asymmetrical combustion temperature, affecting the gasification of the fuel. These effects result in a laminated flow containing both burned and unburned gases rising through the boiler. ROFA creates turbulence and breaks the laminated flow.
- Involves the installation of ROFA injection boxes, fans, dampers, and ducting.
- Achieves NOx reduction greater than 50%.

2. ROFA + ROTAMIX (Rotating Mixing) System

- 2nd generation SNCR
- Works in conjunction with the ROFA system and injects ammonia or urea into the boiler using the same high velocity air as used in the ROFA system.
- Through the ROFA ports, i.e. ROTAMIX, the injection of chemicals into the furnace is easily made and is more efficient than other injection techniques. As a result, the chemicals are thoroughly mixed in the flue gas allowing the reducing agent to be used more effectively resulting in higher reduction levels.
- The combination of the ROFA and Rotamix systems will reduce NOx in the range of 75%.

3. ROFA + ROTAMIX + SCR

- Maximum NOx reduction is achieved by combining ROFA and ROTAMIX with a catalyst (SCR).
- Can achieve a total of 85 to 90% NOx reduction.

Features

- Significant NOx reductions.
- “Invisible” to Operations Personnel.
- Potential to avoid SCR’s.
- Applicable with various fuels such as coal, oil, wood, natural gas, municipal waste, and peat.
- Applicable with various combustion equipment such as burners, grates, spreader stokers, fluidized beds.
- Requires no modifications to burners.
- Lower NOx removal cost than LNB/OFA.
- Auxiliary power increase due to fans required.

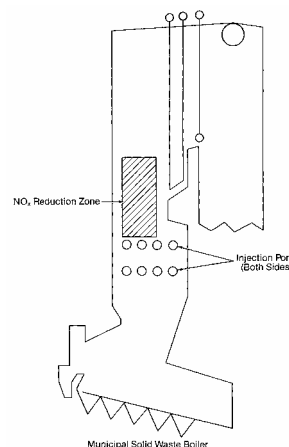
Gryphon International Engineering Services Inc.

C. Post-Combustion NOx Removal

- NOx is reduced downstream of the combustion zone to nitrogen and water through a series of reactions with a chemical agent injected into the flue gas.
- These post-combustion NOx control systems are called selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR).

Selective Non-Catalytic Reduction (SNCR)

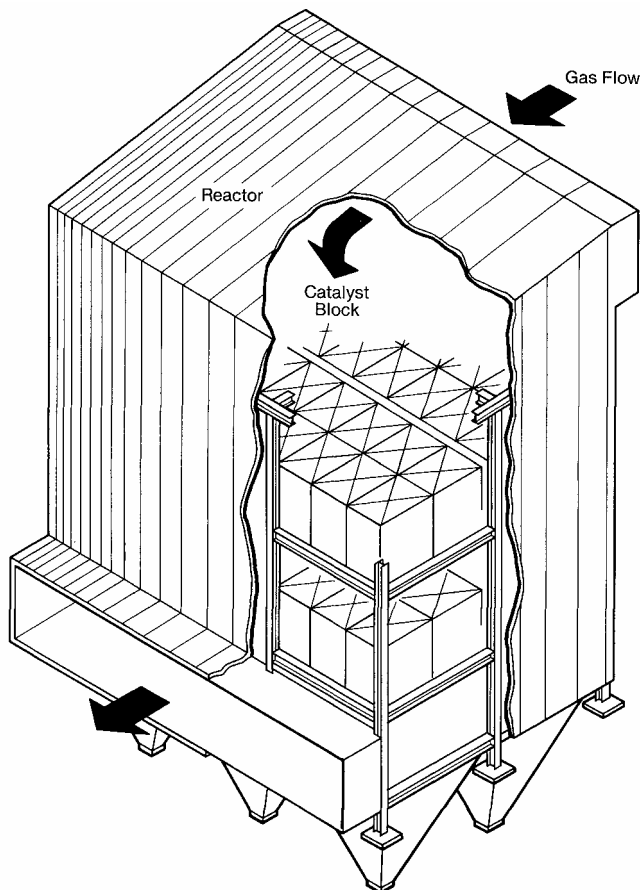
- Ammonia or urea are injected into the flue gas within a specific temperature window (1400 – 2000 °F) to reduce the NOx to water and molecular nitrogen.
- Below 1600 °F chemical enhancers such as hydrogen are needed to assist the reactions.
- Multiple injection zones may be required due to changing temperature profile with boiler load.
- SNCR system consists of storage and handling equipment for the ammonia or urea, equipment for mixing the reducing agent with the carrier (compressed air, steam or water), and the injection equipment. The injection equipment consists of nozzles located at various elevations on the furnace wall.
- Ammonia is usually injected into the gas stream in a gaseous state (Exxon Thermal DeNOx), while urea is injected as an aqueous solution (EPRI process).
- When injecting ammonia or urea, it is important to control the excess unreacted ammonia. Excess ammonia can react with other combustion species such as SO₃ to form ammonium salts such as ammonium sulphate. These cause fouling and corrosion when deposited on downstream equipment, and may contribute to plume formation.
- Reduction levels of 70% are possible under carefully controlled conditions. NOx reductions of 30 to 50% are more typical based on acceptable levels of reagent consumption and unreacted ammonia carryover.
- Most of the current applications are on small municipal solid waste or biomass boilers, where the appropriate temperature range is in the upper furnace. In large utility units, the proper temperature range occurs in the convection pass cavities, making application more challenging.



Typical SNCR Application (from Ref. [1])

Selective Catalytic Reduction (SCR)

- NO_x is reduced by ammonia to molecular nitrogen and water over a catalyst within an optimal temperature range.
- Before entering the catalyst, ammonia is injected into and mixed with the flue gas.
- The NO_x reduction reactions take place as the flue gas passes through the catalyst chamber. The catalyst allows the reactions to take place at a lower temperature. The SCR reactions take place at optimal temperature range of 450 to 840°F, but optimum performance occurs between 675 and 840°F.
- The minimum temperature varies and is based on fuel, flue gas properties, and catalyst formulation, SO₂ content.



SCR Module (from Ref. [1])

- Catalyst formulation is the key to SCR system performance. Three categories of materials:
 1. **Base metal catalyst** – titanium oxide with small amounts of vanadium, molybdenum, or tungsten. The major drawback to the base metal catalyst is the potential to oxidize SO₂ to SO₃, which then reacts with ammonia carryover to form corrosive ammonium sulphate salts.
 2. **Zeolite catalyst** – aluminosilicate materials which have a higher operating temperature of 970°F. This catalyst also has the drawback of oxidizing SO₂ to SO₃.
 3. **Precious metal catalyst** – manufactured from platinum and rhodium. These have high material costs and there is little operating experience. Also,

these catalysts can act as oxidizing catalysts, converting CO to CO₂ and SO₂ to SO₃.

- Various catalyst configurations:
 - Pellets in a packed bed – effective for NO_x reduction but difficult to handle and significant pressure drop.
 - Block type catalyst – larger block modules are easier to handle and install.
 - i. plate type – less pressure drop and less susceptible to plugging and erosion.
 - ii. honeycomb – requires less volume for a given surface area.
- Catalyst is housed in a reactor which is strategically located within the system.
- Ammonia can be anhydrous or aqueous. Most commercial experience has been with anhydrous ammonia. Due to safety concerns, aqueous ammonia is required for some installations.
- The ammonia is transported to site and stored in specially designed tanks. Ammonia is then fed to a vaporizer/mix chamber where it is mixed with air or steam at about a 1:20 volume ratio. The mixture is introduced into the flue gas in an even distribution by an injection grid system. Ammonia is injected at a constant NH₃/NO_x mole ratio. A slightly higher than stoichiometric ratio of 1:1 is injected to account for unreacted ammonia carryover (ammonia slip).
- Most catalysts are toxic and create disposal problems.

SO₂ Control

Gaseous SO₂ combines with liquid water to form sulfurous acid (H₂SO₃). H₂SO₃ easily oxidizes in the atmosphere to form sulfuric acid (H₂SO₄). H₂SO₄ is a major constituent of acid rain.

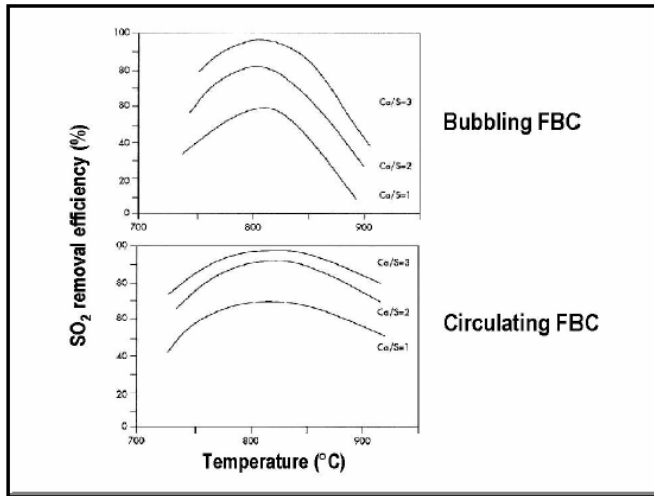
A. Pre-Combustion Techniques

- Fuel substitution.
- Fuel cleaning processes – physical, chemical, biological.

B. Combustion Modifications

High Temperature SO₂ Capture During Fluidized Bed Combustion

- A benefit of fluidized bed combustion is the option of in-situ SO₂ capture.
- The temperature level of 800 ~ 950 °C is such that CaSO₄ is a stable compound.
- By adding a calcium-based sorbent to the fuel/bed material mixture, the SO₂ can be effectively captured immediately after it has formed.

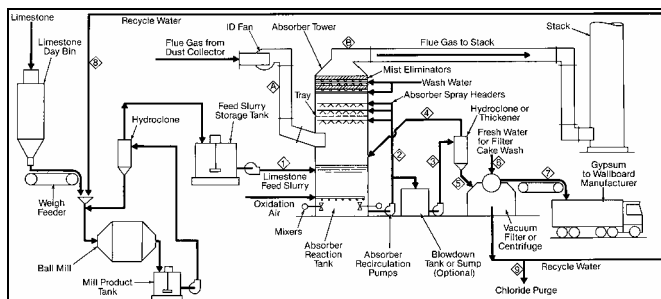


Sulphur Dioxide Capture with Calcium-based sorbents in Bubbling or Circulating FBC (from Ref. [2])

C. Post-Combustion Methods

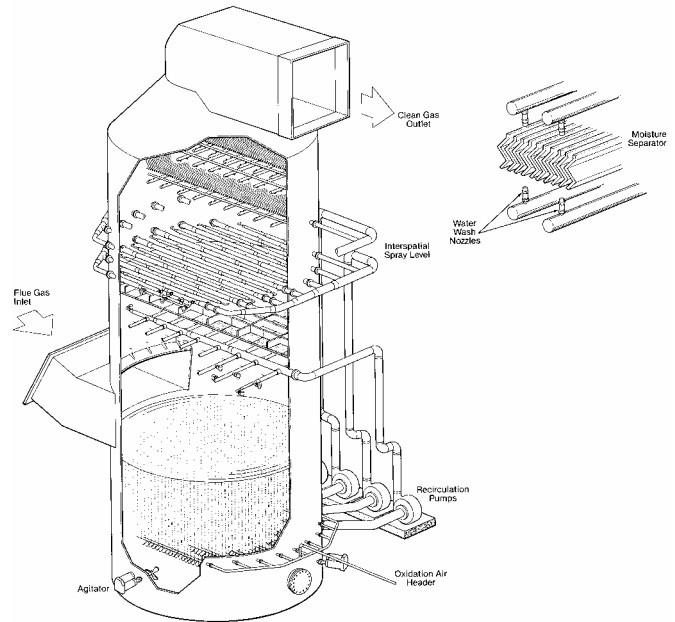
Wet Scrubbers

- Wet Flue Gas Desulphurization (FGD).
- The typical arrangement has an ESP upstream of the wet scrubber, with the induced-draft fan between the ESP and scrubber. Sometimes a booster fan is placed downstream of the scrubber.



Wet Scrubber FGD System Flow Diagram (from Ref. [1])

- Spray tower design is most popular.
- Flue gas enters the side of the scrubber module at a temperature of 250 to 250°F and is cooled to its adiabatic saturation temperature by a slurry spray. Flue gas passes vertically upward through the scrubber. The gas flow is uniformly distributed by a perforated plate or sieve tray. The tray also serves as a gas-liquid contacting device. Above the tray there are several levels of sprays which achieve additional gas-liquid contact. A disengagement height is provided above the top spray to allow the largest slurry droplets to fall back to the spray zone. A mist eliminator at the top of the scrubber uses chevrons to remove additional moisture from the flue gas. The flue gas leaves the mist eliminator saturated with water vapour and some carryover of slurry droplets. Surface condensation is inevitable and the condensate can become very acidic. To minimize these effects, reheating the flue gas or lining the flue/stack is required.



Wet Flue Gas Desulphurization Module (from Ref. [1])

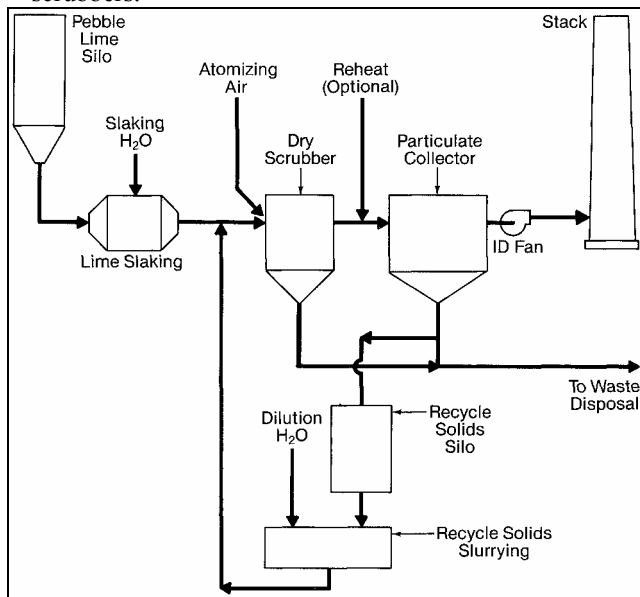
- Slurry reagent is an alkaline earth material such as limestone, lime, dual alkali, soda ash, or magnesium oxide.
- The slurry reagents are non-regenerable – they are consumed by the process and must be continually replenished. There are four process steps for the nonregenerative process:
 1. Reagent Preparation – a closed loop ball mill is typically used for on-site wet grinding of limestone for slurry preparation. Off-site grinding may also be utilized, with the pulverized limestone trucked to site, conveyed to a storage bunker, and fed to water-filled slurry preparation tanks. Lime based systems utilize three type of slaking systems: the detention slaker, the paste slaker, and the ball mill slaker.
 2. SO₂ Absorption – SO₂ absorption and its subsequent reaction with alkaline earth materials is an elementary acid-base reaction. The principal reaction products are calcium sulfite hemihydrate (CaSO₃ · ½ H₂O) and

calcium sulfate dehydrate ($\text{CaSO}_4 \cdot 2 \text{H}_2\text{O}$), or gypsum. Both of these salts have low solubilities. Additives are added for performance enhancement and scale control.

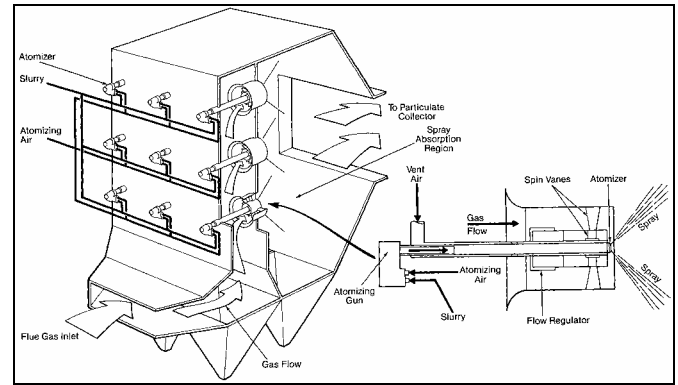
3. Slurry Dewatering – Primary dewatering is accomplished using thickeners or hydroclones. Secondary dewatering is carried out using vacuum drum filters, vacuum belt filters, solid bowl centrifuges, and vertical basket centrifuges.
4. Final Disposal – the simplest disposal method is to store the spent slurry in ponds. However, the most common approach in the U.S. is to landfill the dewatered slurry. Sulfite sludge is mixed with flyash and lime to yield a material suitable for landfilling.

Dry Scrubbers

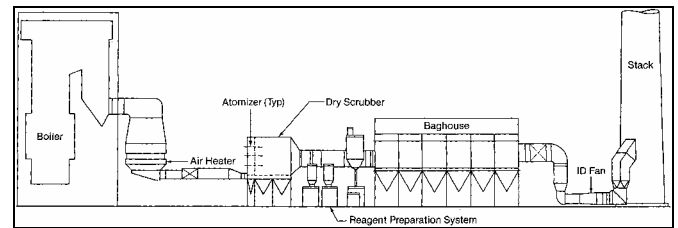
- The principal alternative to wet scrubbers for SO_2 control on utility boilers.
- Dry scrubbers have been mainly applied to units burning low sulphur fuels.
- Advantages of dry scrubbing over wet scrubbing:
 - less costly construction materials
 - dry waste products
 - fewer unit operations
 - simplicity of operation
- Dry scrubbing has higher reagent costs.
- An atomized slurry or aqueous solution of alkaline reagent is sprayed into the hot flue gas to absorb the SO_2 .
- The dry scrubber is positioned before the dust collector (ESP or baghouse).
- Flue gases leaving the air heater at 250 to 350°F enter the dry scrubber through an array of turbo-diffusers. The amount of water is limited in the atomized spray so that it completely evaporates in suspension. SO_2 absorption takes place while the spray is evaporating. SO_2 removal efficiency is dictated by reagent stoichiometry and the approach temperature (difference between flue gas temperature leaving the scrubber and the adiabatic saturation temperature). The flue gas may be heated before entering the dust collector.
- Slaked lime is the predominant reagent used in dry scrubbers.



Dry Scrubber Schematic (from Ref. [1])



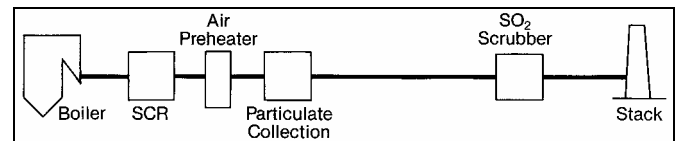
Dry Scrubber Reactor Module (from Ref. [1])



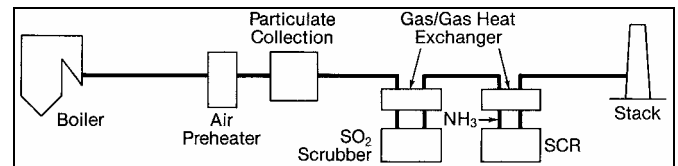
Dry Scrubber Configuration (from Ref. [1])

Combined Boiler Emissions Control Systems

Various combinations of systems for controlling NO_x , SO_2 , and particulate are possible. A few possible configurations are shown schematically below.



Preferred SCR Location (from Ref. [1])



Possible SCR Retrofit Location (from Ref. [1])

EMISSIONS TRADING

- Ontario's emissions trading system covers NO_x and SO₂.
- Emissions trading has been up and running in Ontario since December 31, 2001.
- The Ontario emissions trading system is of the "cap, credit and trade variety".
- Covered by *Emissions Trading Regulation 397/01* under the Environmental Protection Act.
- *Emissions Trading Code* supplements Regulation 397/01
- Currently the regulation covers facilities owned and operated by OPG.
- In 2004 the regulation was expanded to cover all generators over 25 MW capacity or who sell more than 20,000 MWh in a year to the IMO controlled transmission grid.
- *Ontario Emissions Trading Registry* provides:
 1. Notice to the public of the distribution of NO and SO₂ Emission Allowances;
 2. Notice of the application for and the creation of NO and SO₂ Emission Reduction Credits, or ERCs;
 3. Public access to all documentation submitted in support of an application to create an ERC; and
 4. Recording of decisions about credit creation and credit and allowance retirement.

Summary of Emissions Allowances, Trading, and Credit System in Ontario

1. Government specifies emissions caps and distributes allowances for specific groups of emitters.
2. Emitters use market mechanisms to meet their emissions caps.
3. Capped emitters are deemed to have met their responsibilities under this system if their annual emissions are less than the total of the allocations they own and retire, plus the emissions reduction credits they own and retire.
4. Non-capped emitters in the airshed produce emissions reductions credits voluntarily through investments or operational measures. They may bank these credits for their own future needs or for sale to capped entities.

NO_x Emissions Limits and Allowances

- The allowance to each generator is allocated in proportion to electrical energy produced by a generator relative to total electrical energy produced by all generators covered by the cap.
- Allowance allocations are based on electricity production estimates for the coming year, with a true-up early in the year following the allocated year.
- OPG is allocated separate allowance until end of 2007. In 2008, all generators below 48th parallel will be in common pool.
- All generators facing NO_x and SO₂ limits will be required to install CEMs or other emissions monitoring methods approved by MOE that are at least as accurate as CEMs.
- Allowances may be traded freely.
- Banking of allowances is allowed without restrictions.
- NO_x expressed as NO on mass basis.

- Obligation to balance emissions with allowances and credits – penalties not clear.

Ontario NO_x Emissions Allowances 2002-2007

Year	Overall Allowance (kT/yr as NO)	Set Aside (for Renewable Energy & Conservation) (kT/yr as NO)	OPG Allowance (kT/yr as NO)	Other Fossil Gen. Stns. (>25 MW) (kT/yr as NO)
2002	36	1	35	No Cap
2003	36	1	35	No Cap
2004	36	1	25	10
2005	36	1	22.4	12.6
2006	36	1	21.1	13.9
2007	28	1	17	10

Ontario NO_x Emissions Allowances 2008-2010

Year	Overall Allowance (kT/yr as NO)	Set Aside (for Renewable Energy & Conservation) (kT/yr as NO)	PEMA (all plants south of 48 th parallel) (kT/yr)	Non-PEMA (all plants north of 48 th parallel) kT/yr
2008	28	1	24.6	2.4
2009	28	1	24.6	2.4
2010	28	1	24.6	2.4

Notes:

PEMA = Pollution Emission Management Area
kT = 1000 tonnes

SO₂ Emissions Limits and Allowances

The rules for SO₂ emissions limits and allowances are similar to the rules for NO_x described in the previous section.

Ontario SO₂ Emissions Allowances 2002-2010

Year	Overall Allowance (kT/yr SO ₂)	Set Aside (for Renewable Energy & Conservation) (kT/yr SO ₂)	OPG Allowance (kT/yr SO ₂)	Other Fossil Gen. Stns. (>25 MW) (kT/yr SO ₂)
2002	157.5	4	153.5	No Cap
2003	157.5	4	153.5	No Cap
2004	157.5	4	153.5	
2005	157.5	4	153.5	
2006	157.5	4	153.5	
2007	131	4	127	
2008	131	4	127	
2009	131	4	127	
2010	131	4	127	

Emissions Reduction Credit (ERC)

- Credits given for true emissions reductions.
- ERCs can be created by any emitter not facing obligations under the regulation who takes positive action to reduce emissions at their site. Credits cannot be created by cutting back on production.
- Eligibility is limited to 12 Ozone Annex states (NY, PA, NJ, DW, MD, WV, KY, OH, MI, IN, IL, WI), DC, and Ontario.
- ERC's able to be created for NOx reduction projects, renewable energy projects, and energy conservation projects.
- A reduction action will be able to create ERCs for 7 years from the date the initiative becomes operational; or until emissions from the facility or sector are included in emissions trading regulations; or until other emissions regulations reduce allowable emissions.
- 90% of ERCs may be used to meet obligations – 10% discount of all used ERCs for benefit of environment.
- ERCs may be traded freely or banked.
- MOE will approve ERCs prior to registration with Emissions Trading Registry.
- Emissions Trading Registry for trading, tracking ownership and use, and public review of ERC documentation.

ERC Creation

- Facilities which have received emissions allowances cannot create ERCs (they could actually trade or bank the allowance if their emissions were below the allowance).
- ERCs are created by reducing NO by implementing an approved Standard Method.
- Suggestions for new Standard Methods should be made to the Director.

Standard Methods (for Emission Reduction Credits)

- Description of science supporting the emissions reduction.
- Complete step-by-step method to be used for the computation of emission reductions.
- Standard Methods for emission reduction are given in Appendices of Emissions Trading Code.
- Emissions reductions are calculated as the difference between the baseline emissions and the emissions that occur after the implementation of the emission reduction project.
- The “baseline” is defined as “the emissions that would be expected to occur in the absence of the emission reduction project”. The baseline determination method is described in the Standard Method.

Protocol (for Emission Reduction Credits)

- A document that describes a specific emission reduction project.
- Key document in the review, verification, creation, and recording of ERCs.
- Recorded on the Registry.
- Emissions reductions must be achieved in accordance with a Standard Method.

Emission Reduction Reports (for Emission Reduction Credits)

- Annual report submitted - quantifies actual emission reductions from the emission reduction project described in the Protocol.
- A verification report prepared by a qualified independent third party is submitted as part of the Emission Reduction Report. The verification report indicates whether the emission reduction is surplus, real, properly quantified, and unique.

Emission Trading Mechanisms

- Emissions allowances, credits, retirements, and trades are kept track of on the Ontario Emissions Trading Registry. (<http://www.ene.gov.on.ca/envision/air/etr/>)
- There is currently no formal trading system for trading, buying, or selling emissions allowances and credits. The MOE has expressed no plans to set up such a system. Private negotiations must be carried out between companies for trading emissions, with transactions recorded on the Registry.
- There are significant challenges to be overcome related to transboundary trading (Ontario-U.S.).
- Through Environment Canada, the federal government of Canada has expressed the concern that trading between capped and uncapped sectors is not consistent with Canada's obligations and commitments under the Ozone Annex [Ref. 4]. In the U.S. SO₂ and NO_x cap and trade programs, the trading of allowances allocated under the caps and credits generated outside of the caps has not been permitted. In order to move forward in transboundary emissions trading, Ontario may need to establish NO_x and SO₂ caps for industrial sources in addition to the electricity sector.
- In Ontario, NO_x mass emissions are expressed as NO. In the United States, NO_x mass emissions are expressed as NO₂. One tonne of NO is equivalent to approximately 1.5333 tonnes of NO₂. This conversion factor must be kept in mind for NO_x emissions trading between Ontario and the United States.

CONCLUSIONS

Various technologies exist for significantly reducing boiler air emissions. These technologies are generally pollutant-specific, and multiple technologies may have to be combined to achieve required emissions levels.

There has been significant activity in recent years in updating environmental regulations in Ontario. NO_x and SO₂ caps are being imposed on the electricity sector, and the capped emitters must utilize emissions trading to meet their emissions caps. There are additional changes which are currently proposed which will affect the dispersion modeling, air standard setting, and approvals process. The province of Ontario is clearly moving toward a U.S.-style of environmental regulation.

These changes in environmental policy and environmental regulations will push the drive toward the implementation of

boiler emissions control technologies, starting initially with the electricity sector, and progressing toward the industrial sector.

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