



Clearing the Air

Pollution-control technology for coal-based power plants



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Citation: Priyavrat Bhati and Soundaram Ramanathan, *Clearing the Air*, Centre for Science and Environment, New Delhi

Published by
Centre for Science and Environment
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Printed at Multi Colour Services, New Delhi

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Introduction

On 7 December 2015, the government published new environmental norms for coal-based power plants. The regulations aim to drastically cut down emissions of particulate matter (PM), sulphur dioxide (SO₂) and oxides of nitrogen (NO_x), and bring them closer to international standards (see *Table 1: Emission standards in key countries*). In addition, the new norms will require power plants to sharply curtail freshwater use.

TABLE 1: EMISSION STANDARDS IN KEY COUNTRIES

India's recent emissions norms for new plants are at par with global standards (in mg/ Nm³)

Country	PM	SO ₂	NO _x	Mercury
INDIA				
Current standards	150-350	None	None	None
New standards				
Units installed before 2004*	100	< 500 MW: 600 ≥ 500 MW: 200	600	≥ 500 MW: 0.03
Units installed between 2004–16*	50	< 500 MW: 600 ≥ 500 MW: 200	300	0.03
Units installed after December 2016	30	100	100	0.03
CHINA	30	100	100	0.03
USA-NSPS/NESHAP	14.5	100	100	0.0017

*For existing units, norms come into effect beginning 7 December 2017.
Source: Ministry of Environment, Forests and Climate Change (MoEF&CC)

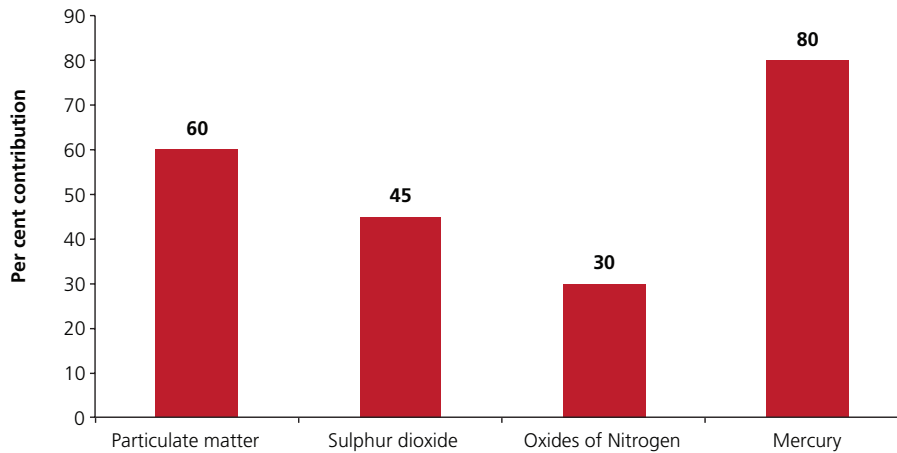
The tightening of standards was the first revision in almost two decades and was prompted by increasing concerns about worsening air quality and its health impacts. Coal-based thermal power industry is responsible for a significant share of emissions from the industrial sector in India and, therefore, it has a big impact on air pollution (see *Graph 1. Contribution of coal-based power sector to industrial emissions*).

Against this backdrop, power plants were required to meet only PM emissions norms, which were way looser than those in China, US and EU. Furthermore, two-thirds of the power plants failed to comply with even these lenient standards, as revealed by a 2015 study by CSE.

There were no national regulations for SO₂, NO_x and mercury emissions from power plants. Standards were specified only for the chimney height to ensure the flue gas, which is loaded with these pollutants, is dispersed. This dispersion was meant to limit incremental ambient concentration. However, increasing levels of pollution from other sources, combined with sharp growth in thermal power generation, has made this control method inadequate.

GRAPH 1: CONTRIBUTION OF COAL-BASED POWER SECTOR TO INDUSTRIAL EMISSIONS

Coal-based power sector is the biggest contributor



Source: Centre for Science and Environment, 2014–15

With coal-based capacity projected to increase to 250 GW in the next three-five years (from the current 186 GW), there would be seriously damaging impact on air quality and health unless stringent controls are put in place. The Central Pollution Control Board (CPCB) and Ministry of Environment, Forests and Climate Change (MoEF&CC) conducted in-house studies and commissioned research from external experts on the environmental impacts and pollution control technology options based on which tighter, comprehensive emissions standards for coal-based power plants were announced.

According to CPCB, the new standards considered a range of factors like age of the units, plant technology, potential for upgradation and retrofitment, existing regulations, and environmental clearances (ECs). For example, ECs after 2003 required large units to leave sufficient space to install pollution control equipment. New norms were framed keeping this in mind.

Rationale for the new norms

The norms categorize power plants into three groups—units installed prior to 2004, between 2004 and 2016, and to be commissioned after 2016—and specify different standards for each category. The rationale for the groupings can be broadly summarized as follows:

1. Older units (especially those more than 25 years old) will have limited time to recover investment in new technology or significant renovations. Improvement in performance may be limited by their dated technology. Therefore, the new standards for this group are relatively loose—plants should be able to comply with them mostly by renovation.
2. Units that were installed 2004 onwards should be able to meet tighter standards given their advanced technology. Many have better boiler combustion design with low NO_x emissions or electrostatic precipitators (ESPs) that were designed for low PM emissions. They also have longer life remaining, which allows the owners to make larger investment in installing new equipment to meet tighter PM standards. EC requirements mean

that larger units have to leave space for installing flue-gas desulfurization (FGD), given their higher pollution load. For these reasons, tighter SO_x norms are justified for newer and larger units.

3. Upcoming units are required to have super-critical technology and state-of-the-art pollution control equipment and should meet the most stringent standards.

Challenges

While the new tighter air emissions regulations are a welcome step, a lot needs to be done to ensure compliance. In the past, the power sector has set ambitious goals but failed to deliver. In 1999, the then Ministry of Environment and Forests (MoEF) directed the power sector to use 100 per cent of the flyash generated by it by 2009. The deadline was later extended to 2014 but the industry is no closer to compliance with usage stuck at around 60 per cent. In 2003, the power sector had agreed on improvements in its environmental performance under the voluntary Charter on Corporate Responsibility for Environmental Protection programme, which included tighter PM emissions standards—most plants still don't meet those standards.

The new norms will come into effect from December 2017 for the existing plants. At the time of adoption of the new norms in December 2015, a two-year compliance timeline was put in place to prod the industry to move quickly. Timelines are tight but were achievable when the norms were announced. However, little progress has been made over the last 11 months, during which the industry could have completed pre-execution work (needs assessment, cost estimates and tariff application). Meeting PM and NO_x norms is still possible, given construction time of less than six months, installation can be done during scheduled shut down or may need less than one month of shut down. However, procurement and installation of an FGD unit could take longer.

Another issue being raised by several plants is that Indian coal is of poor quality with high ash content, which means power plants may need pollution control devices designed for Indian coal.

Historically, the operating practices of Indian plants have been poor. A number of plants did not undertake renovation and maintenance, in particular that of the pollution control equipment, in a timely manner. The result is ESPs and other pollution control equipment are performing below their design capabilities in most of the plants.

Current status

An informal survey of several power plants and manufacturers of pollution control devices by CSE has revealed that the industry has made little progress over the last 11 months. Many companies are in the early stages of assessing needs or asking contractors and manufacturers for clarifications. Some are hoping the standards will be loosened or the date will be extended and have done no needs assessment. Worse, a few projects are moving ahead under old plans, which may mean expensive modifications later on.

Indian plants have installed ESPs to control PM, however, most units are not meeting the emissions standards. A number of units have ESPs that were

designed to meet the norms—these may just need to undergo refurbishment or basic upgradation. However, older units may have been designed to meet lower standards or performance of their ESPs may have significantly deteriorated—these will have to consider major overhauls.

Since regulations did not require SO₂ and NO_x abatement, very few plants have installed pollution control technology such as FGD or selective catalytic reduction units (SCRs) to cut SO_x and NO_x emissions. Industry executives and regulators have limited knowledge about these technologies or experience of their operations.

Objectives of this report

This document aims to give a detailed overview of the pollution control technologies for units of different vintages and sizes and the norms the units need to meet. The document hopes to achieve the following:

- Confirm for policy makers that the new norms are achievable and practical and can be met with widely available, mature technological options at a reasonable cost.
- Assist the environment and tariff regulators (Central Electricity Regulatory Commission (CERC)/ CPCB) in building technical know-how.
- Provide benchmark costs of various technologies and be a resource for Central Electricity Authority (CEA) to prepare a technology guidance document for the industry and other regulators.
- For certain old units, provide alternatives that are techno-economically preferable to large investments. It may be better to shut old plants within short time frames rather than make significant investments in their renovation.
- The document could also be used as a handy tool to build capacity of all stakeholders.

Pollution control technology

Technologies to control particulate matter, sulphur dioxide and nitrogen oxides emissions are mature. They are being used across the world for a range of coal quality and operating conditions. Many large-scale manufacturers, including BHEL, Mitsubishi and GE-Alstom, are supplying the technologies to meet the new standards.

In this report, we provide an overview of the various technological options based on the size and vintage of units, required emission levels that need to be achieved, indicative range of investment needed and installation time required. The two most important parameters to decide what pollution-control options are most appropriate are age and size of the unit (see *Table 2: Unit size distribution in India*).

TABLE 2: UNIT SIZE DISTRIBUTION IN INDIA

Bulk of the industry comprises of large and relatively new units

Unit size in MW	Capacity in MW				
	+ 25 years	1990–2003	2004–08	2009–16*	Total
Up to 250	28,610	16,292	2,070	5,816	52,788
> 250 and <500	-	5,350	3,850	20,810	30,010
500 and above	5,500	9,500	5,980	82,814	103,794
Total	34,110	31,142	11,900	109,440	186,592

Note: *As on 31 August 2016

Source: Centre for Science and Environment

Our broad assessment is that 152.4 GW capacity installed between 1990 and 2016 would require varying degree of ESP upgradation and burner modification, and in some cases installation of SCNRs, to meet the emissions standards of particulate matter and oxides of nitrogen. FGD units—both limestone-based wet or lime-based dry—would be required to control sulphur dioxide emission from units of size 500 MW and above (98.3 GW installed between 1990 and 2016). Units smaller than 500 MW—about 54.2 GW installed capacity—can choose economical options such as partial FGD, circulating bed dry FGD etc.

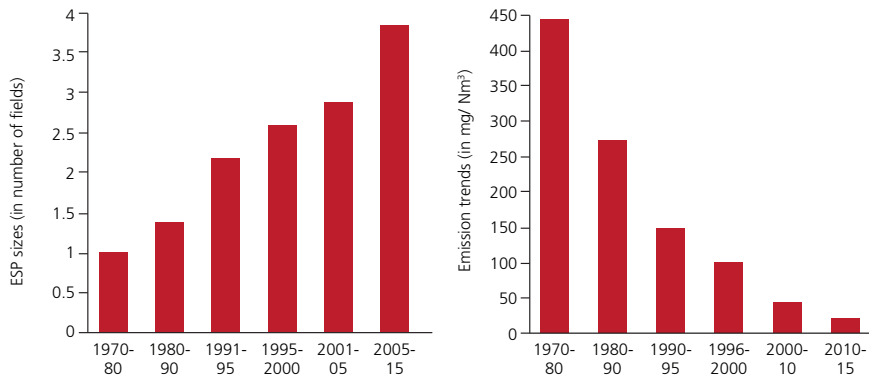
Decisions to make significant investments in pollution control equipment in stations that have exceeded their useful design life (+25 years plants) must be considered taking into account plant efficiency, cost of power production and environmental impact.

Particulate matter

Power plants generate dust of about 10 microns size on burning pulverized coal. Existing standards limit emissions of suspended particulate matter through the stack into the air to 150–350 mg/ Nm³ (based on size and vintage of the unit). Since August 2008, ECs given to power plants have been requiring them to meet the PM standard of 50 mg/ Nm³. As the norms have steadily tightened, dry electrostatic precipitators have been designed with larger sizes (see *Annexure*).

GRAPH 2: COMPARISON OF EMISSION TRENDS AND SIZES OF ESPs IN INDIA

After 2000, ESPs were designed to meet PM standards of 50 mg/ Nm³



Source: Mitsubishi Hitachi Power Systems

The emissions inventory published by CEA and the environmental clearances norms set by MoEF&CC suggest that the bulk of the existing plants are either meeting the PM norms or have ESPs that were designed to meet the norms. This implies only 67 GW of capacity needs to materially upgrade their ESPs. However, we believe CEA data paints an optimistic picture—CSE’s *Heat on Power* indicated that almost two-thirds of the units were not complying with the PM norms, but most of them were reporting that they were in compliance. A larger percentage of the total capacity may, therefore, need to upgrade its ESPs (see *Table 3: Indian fleet—particulate emissions*).

TABLE 3: INDIAN FLEET—PARTICULATE EMISSIONS

According to CEA data, nearly two-thirds of the plants comply with particulate emissions norms

Emissions in mg/ Nm ³	Capacity in MW	Prior to 2003	Post-2003
0–50	98,548	3,147	95,401
50–100	27,335	14,880	12,455
100–150	34,173	28,953	5,720
150–250	9,553	7,133	2,420
250–500	8,398	8,398	-
500+	2,493	2,493	-

Source: Central Electricity Authority (CEA) and MoEF&CC

Note: Performance is mostly understated. CSE estimates two-thirds in violation. MIT’s study in Gujarat also had similar estimates on the number in violation.

Reasons for deviation from design

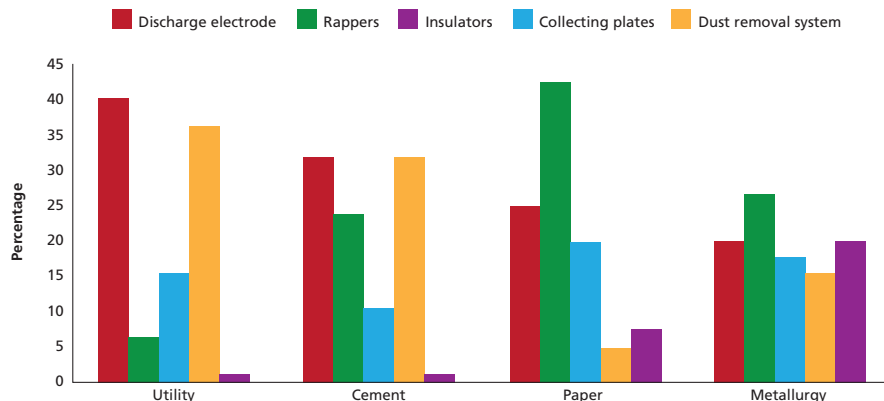
Though the ESPs were designed to operate with an efficiency of 99.9 per cent to limit PM levels to below 50 or 100 mg/ Nm³, the emissions are much higher because performance has deteriorated due to poor maintenance (see *Graph 3: Problem areas in ESPs*). The major issues in maintenance may be explained as follows:

1. Dust removal systems

A field survey by experts indicates hopper level switches are bypassed deliberately to avoid labour costs. Mismatch of flyash evacuation system and ESP ash dislodging capacity exacerbates the issue. Hoppers are filled with ash up to 60 per cent of their height. The ash in the hoppers damages the system. Even after removal, electrodes suffer misalignment and sometimes permanent deformation.

GRAPH 3: PROBLEM AREAS IN ESPs

Major maintenance issues reported in discharge electrodes and dust removal systems



Source: ESP Technologies Pvt Ltd

2. Discharge electrodes

Discharge electrodes suffer mechanical damage when the system is operated at an inappropriate voltage—operating above specified voltage leads to sparks, which cause erosion of the electrodes. Fatigue, erection misalignments and improper dust removal can also lead to damage.

The preliminary assessment of existing ESPs should, therefore, consist of a review of their performance deviation from design and assessing issues related to the voltage in electrodes.

Refurbishment techniques

For ESPs that were designed for higher emission levels and require upgradation, the following techniques can be considered, on a case-to-case basis, depending on space and technical parameters.

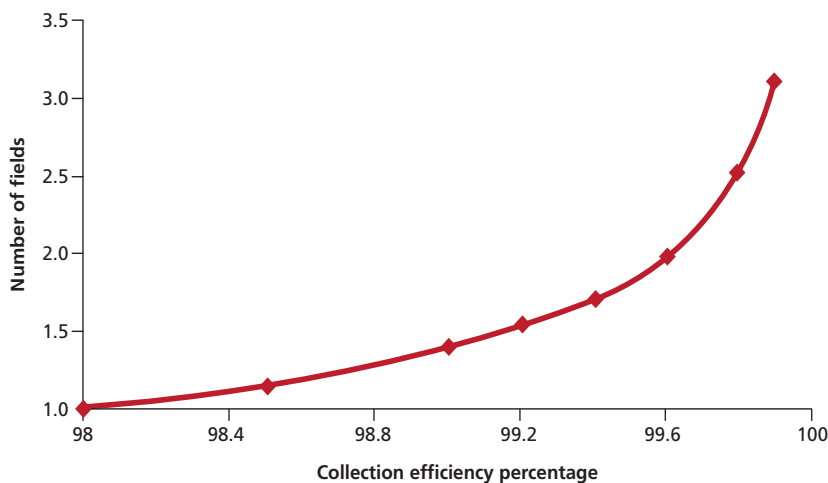
Preferred solutions

Increase in specific collection area has been tried in several retrofit installations and has led to dramatic increase in collection efficiency. Any of the following can be done to increase the specific collection area of an ESP:

1. **Adding fields in series to an existing ESP:** This solution is recommended when sufficient space exists (see *Graph 4: Size of ESP vs collection efficiency*).
2. **Placing additional ESPs parallel to an existing ESP:** When adding fields in series is not feasible due to space constraints, addition of ESPs in parallel is recommended. Parallel ESPs have multiple inlets in contrast to series ESPs, hence they require redesign of flue gas flow and dust redistribution calculations. Multiple inlets for parallel ESPs would lead to excess pressure drops and higher electricity consumption.

GRAPH 4: SIZE OF ESP VS COLLECTION EFFICIENCY

To improve collection efficiency from 99.2 to 99.8 per cent, the size of ESPs needs to be doubled



Source: ESP Technologies Pvt. Ltd.

3. **Adding new internals by increasing the casing height:** When neither parallel nor series addition is possible, and improving collection efficiency by increasing the specific collection area is a necessity, this method is suitable. Wider spacing is created between electrodes when increasing the height so that civil foundation load does not increase; to compensate for the wider spacing, higher frequency transformer-rectifier sets are used.
4. **Replacing old ESPs with new ones:** Suggested when significant improvement is required in collection efficiency and the performance of old ESPs is seriously degraded.
5. **Filling the dummy fields of ESPs:** This option may be available for only a few units, it involves filling electrodes in a compartment that was left empty during early phases of the construction for later augmentation.

Solutions relevant for minor improvement

The following are some other advanced solutions suggested for minor reduction of emissions. These techniques are suitable mostly for low resistive dust and coarse ash particle (see *Annexure* for more details on these techniques).

1. **Optimizing power supply:** Switch mode power supply units are suggested to lower ripple voltage delivered to ESPs which can lower its performance.
2. **Introducing more bus bars and transformer rectifier sets:** Corona power is increased by introducing new bus bars and improving voltage of the ESPs. This method is suitable for low resistivity and coarse particle ash.
3. **Conditioning flue gas (FGC):** Ammonia, sulphur trioxide and sodium can be used as reagents for conditioning flue gases by constructing a simple mechanical system. However, this may result in contaminated ash generation. Improper maintenance of the system can lead to corrosion and clogging.
4. **Introducing a bag filter in an existing ESP's casings, changing electrodes etc.**

Conclusions

The sector is capable of achieving particulate matter emissions norms given that a considerable proportion of plants have ESPs designed to meet the norms and only minor refurbishments are needed.

The renovation of ESPs would cost between Rs 5–15 lakh per MW, depending upon the extent of upgradation. The shutdown time for retrofitment may be up to 30 days, subject to the technique chosen for refurbishment.

1. Basic upgradation may suffice for units which have exceeded their design life of 25 years (approximately 34 GW capacity) since it might be preferable to retire them in the near future. However, plants with good operating performance and significant remaining life because of life extensions may consider upgrading the ESPs.

For example, NTPC Rihand, whose performance is good (gross efficiency of 36 per cent), is upgrading its 25 year-old ESP to meet PM norms of 50 mg/ Nm³. It is installing advanced moving electrode electrostatic precipitator technology in two fields (the remaining four fields in the middle will remain fixed-electrode type) of the ESP. This technology is expected to reduce emissions from around 400-500 mg/ Nm³ to 50 mg/ Nm³.

2. Plants and units commissioned between 1990 and 2008 (total capacity: 43 GW) will have to undergo upgradation to meet the norms of 100 or 50 mg/ Nm³. ESPs in a number of these plants were not designed to meet the new standards. The collection area in the ESPs may not be sufficient. They will need to add more fields (in series or parallel) or may need to increase the casing height.
3. A vast majority of the 109 GW of capacity installed after 2008 was required to meet PM standard of 50 mg/ Nm³ under their ECs, the same level as the new norms. Many of these plants should already be in compliance, some may require basic refurbishment such as optimizing gas flow distribution and reducing leakages. Optimizing the energy supply and control systems are other revamping techniques to improve performance without significant investments. However, 30-45 GW of this capacity was required to meet 100-150 mg/ Nm³—these may require ESP augmentation.
4. Units in the pipeline should be able to meet the 30 mg/ Nm³ standard with a combination of ESPs and FGD units. In fact, an integrated design would mean that the ESP size can be made smaller than a standalone one for meeting the norms.

Sulphur dioxide

While Indian coal contains little sulphur (~ 0.4–0.6 per cent), its calorific value is also low. Indian plants use relatively large quantity of coal per unit of electricity generated. As a result, total SO₂ emissions from Indian plants are high and need to be controlled. Images released by NASA’s Aura satellite show doubling of sulphur dioxide concentrations in India from 2005 to 2012. Emissions inventory estimates published by Zifeng Lu, a scientist at Argonne National Laboratory and the US Environmental Protection Agency, confirms India as the second largest emitter of SO₂ in the world, a significant share of which is produced by coal-based power plants.

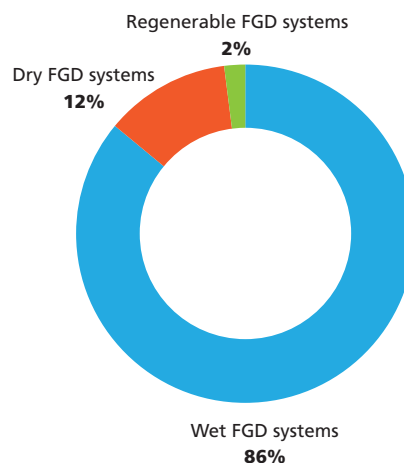
SO₂ emissions can be controlled by three methods:

- Before combustion, by lowering sulphur content in the fuel.
- During combustion, by injecting sorbents such as limestone.
- After combustion, by treating flue gas with sorbents in FGD devices or in ducts.

However, finding fuel with low sulphur content and acceptable gross calorific value is a challenge. Sorbent injection during combustion, though successful in smaller plants, has not been established for utility or larger plants. That makes FGD the most widely-used technology because of its high capture rate. The technology is mature—it has been used for several decades in a variety of operating conditions and for coals of different compositions (see *Graph 5: FGD technology—global population*).

GRAPH 5: FGD TECHNOLOGY—GLOBAL POPULATION

Wet FGD technology dominates the global market



Source: USEPA, 2003

According to Transparent Technologies Pvt Ltd, over 90 per cent of the worldwide FGD systems are wet. Post-2003, no worldwide survey on FGD installations has been carried out. During this period, most FGD units were constructed in China as US had already stabilized its capacity; 90 per cent of the FGD systems installed in China are wet.

In India, since there were no national norms for SO₂ emissions, only 6 GW of coal-based power stations have installed FGD systems. Although Maharashtra and Gujarat have mandated limits on SO₂ emissions, there has been no enforcement—plants routinely submit environment statements that report very low SO₂ emissions, although they haven't even installed SO₂ control devices.

FGD technology

An FGD device is a chemical vessel which captures sulphur dioxide in flue gas (see *Annexure*). Sulphur dioxide is made to react with an alkali, usually limestone, owing to its cheap and wide availability, to precipitate the pollutant as salt (gypsum). The major FGD systems are summarized as follows:

Limestone-based wet FGD units

- Limestone slurry is pumped into the vessel to dissolve SO₂ in the flue gas.
- Gypsum is generated as waste. It can be used as fertilizer or construction material.
- The limestone-based wet FGD systems requires 0.2–0.3 m³/ MWh water.

Dry FGD units

- In some cases, scarcity of water drives installation of dry FGD systems, which mainly use slaked lime and, in some cases, limestone.
- The result is calcium sulphate/sulphite salts as waste which are of no use in markets currently and needs to be disposed of in a landfill.

Seawater FGD units

- FGD systems which use seawater and do not need limestone are called seawater FGD systems.
- Seawater FGD systems need lesser capital investment compared to other FGD systems and their operating costs are also lower as they require no reagent for operation (see *Table 4: Technology comparison*).

Space requirement

An FGD system has several components—limestone handling, duct area, scrubber and dewatering systems. The space requirement depends on common systems in case multiple units coexist in one place (e.g. 4 x 150 MW or 5 x 800 MW). In such plants, limestone handling and dewatering system can be common for multiple units. Usually two–eight acres space is required for wet FGD units, which can be in fragments. Different sub-components can be situated in non-contiguous areas (see *Table 5: Space requirement for a wet FGD*).

TABLE 4: TECHNOLOGY COMPARISON

Dry FGD units cost less to install, but generate waste which cannot be used, and have higher operating costs

	WET FGD	Dry FGD
Commercially available range	~ 1,100 MW	300–400 MW single absorber For novel integrated desulphurization (NID) each module of 75 MW _e
Types	1) Seawater 2) Freshwater	1) Spray dry absorber (SDA) 2) Circulating dry absorber 3) NID.
SO ₂ removal efficiency	Upto 99 per cent	Upto 99 per cent (90–95 per cent for SDA)
Capital cost	Freshwater FGD: ~50 lakhs/ MW Seawater FGD: ~ 40 lakhs/ MW	~ 35 lakhs/ MW
Sorbent	Freshwater FGD: CaCO ₃ Seawater FGD: No sorbent	CaO/ Ca(OH) ₂
Sorbent use	Approximately 1.5–2 tonne limestone consumed per tonne SO ₂ removal	Approximately 0.75–1.5 tonne lime consumed per tonne SO ₂ removal
Sorbent cost (Rs/ tonne)	~ 2000	~ 6000
Water consumption in m ³ / MWh	0.2–0.25 m ³ / MWh for power plants between 200–500 MW; 0.25–0.3 m ³ / MWh for power plants between 50–200 MW; 0.3–0.45 m ³ / MWh for captive power plants up to 50–70 MW	0.1–0.2 m ³ / MWh for power plants up to 200 MW. The semi dry system is not recommended for power plants > 200 MW
Auxiliary power consumption	Freshwater FGD: 0.7 per cent Seawater FGD: 0.7–1.5 per cent	1–2 per cent
Condition of existing stack	Existing stacks to be modified in all cases	Existing stacks can be used without modification
FGD by-product	Freshwater FGD: gypsum Seawater FGD: no by-product	CaSO ₃ / CaSO ₄ : Has to be landfilled
Waste water	Generates	Doesn't generate
Erection period	Up to 50 MW ~ 12–14 months 50-200 MW ~ 14–18 months 200-500 MW ~ 18–24 months > 500 MW ~ 24–30 months	Up to 50 MW ~ 12–14 months 50–200 MW ~ 14–18 months
Downtime	Up to 50 MW ~ 2–3 weeks 50-200 MW ~ 3–4 weeks 200 MW and above ~ 4–6 weeks	4-6 months (due to renovation/ modification in existing PM control equipment such as bag filter/ ESP)

Source: NTPC Limited

*Assuming sulphur content 0.5 percent in coal and stoichiometric consumption of sorbents.

TABLE 5: SPACE REQUIREMENT FOR A WET FGD

For most plants, the space requirement will not be more than three acre

	1 x 150 MW ¹	4 x 150 MW ⁺	2 X 660 MW ⁺	5 X 800 MW ⁺
Area required for the wet FGD system (acres)	0.6	2.2	2	7.6

¹ Dedicated limestone slurry preparation and dewatering system.

⁺ FGDs have common limestone slurry preparation and dewatering system.

Source: Thermax, 2016

CPCB has clarified that space limitations should not be a constraint for installation of FGD units in power stations having unit size of more than 500 MW, installed between 1 January 2004 and 31 December 2016. In environmental clearance letters issued to these units, provision of space for installation of the FGD units was made mandatory.

Timelines

The construction of an FGD unit involves both civil and mechanical work—installation of scrubbers, gas re-heaters, ducting and chimney lining, or the construction of a new chimney. Typically, construction requires about 18 months for a 500 MW unit. The shutdown time to hook up a wet FGD system to the unit takes upto one month, depending on the chimney construction.

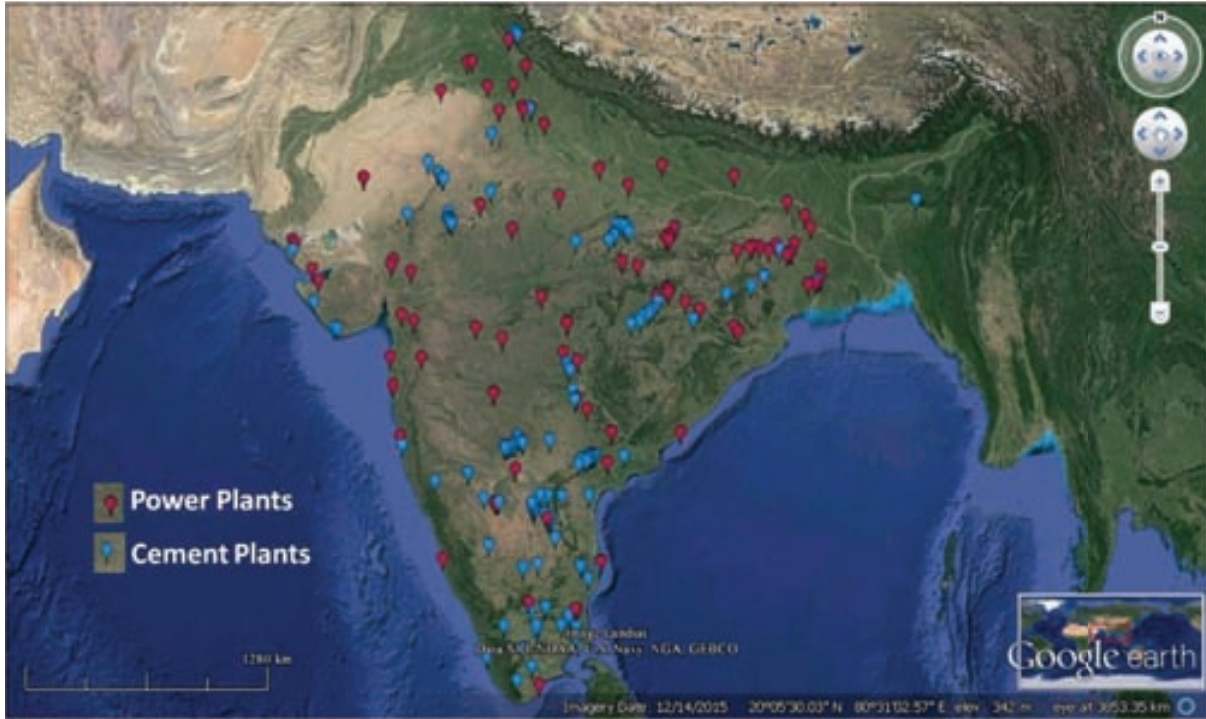
Conclusions

FGD is a proven and mature technology. But FGD devices are the most capital-intensive pollution control retrofit required to comply with the new norms. It is, therefore, important to take into account the techno-economic issues—unit size or technology and age or remaining life, operating performance and cost of generation, emissions, and applicable standards to determine the most appropriate technology to control SO_x .

1. Plants older than 25 years should not be required to install FGD units. They should explore reducing SO_x emissions through sorbent injection or obtaining low sulphur fuel.
2. Plants installed prior to 2003 and smaller than 500 MW (around 54 GW) may need to consider the option of partial FGD—treating a lower volume of flue gas. This process would be less costly, in the range 0.3 cr/ MW, and its installation would suffice to meet the 600 mg/ Nm^3 norms rather than an FGD unit. Partial FGD may also require smaller footprint, which may be a constraint for smaller units. The retrofit costs are approximately 0.25–0.3 cr/ MW.
3. Plants larger than 500 MW (around 98 GW) were required by environment clearances to allocate spare land for possible installation of an FGD unit in future. To meet SO_x standard of 200 mg/ Nm^3 , they will need to install dry or wet FGD units. The retrofit costs are approximately 0.5 cr/ MW.
4. For every kg of SO_2 removal, about 1.5 kg of limestone is required. To control SO_2 from around 150 GW capacity (which are expected to install FGD units), 12–16 million metric tonne limestone will be required annually.
5. The May 2016 Amendment to Mines and Minerals (Development and Regulation) Act, 1957 allows transfer of captive mining leases with a written approval from the state government. Also, state governments allot mining leases via auctions to eligible persons in need of limestone, therefore, power stations can chose to either acquire new mining rights or get existing rights transferred in their name. There is no dearth of the mineral. India has an estimated 170 billion tonnes (bt), of which 7 per cent is under reserve category and remaining 93 per cent under resource category. Annual usage is around 280 million tonnes (mt)—cement industry consumes 269 mt, iron and steel industry 5.8 mt and chemicals industry 3.9 mt (see *Map 1: Location of cement and coal-based power plants*).

MAP 1: LOCATION OF CEMENT AND COAL-BASED POWER PLANTS

Proximity of cement plants to coal-based power plants indicate viability of limestone supply to all power stations



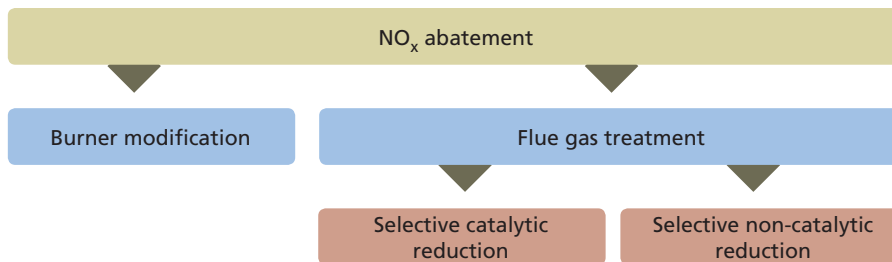
Source: Centre for Science and Environment, 2016

Oxides of nitrogen

About 75 per cent of emissions of NO_x in coal-based power plants comes from the fuel and the rest is largely due to high combustion temperature. NO_x abatement is possible both during and after combustion. NO_x emissions range around $800\text{mg}/\text{Nm}^3$ in Indian coal-based power plants.

FIGURE 1: TYPE OF NO_x CONTROL

Control methods can be employed either during or after combustion



Source: Centre for Science and Environment, 2016

Burner modification

Low NO_x burners are boilers having extra ports to supply air and fuel compared to conventional burners. By altering the air–fuel mix, temperatures at different locations in a boiler are kept below a certain level so reaction between nitrogen and oxygen is minimized and relatively lower quantity of NO_x is formed. These technologies are the basic and most cost-effective control mechanisms. The process has a relatively low capture efficiency of around 50 per cent, which means NO_x emissions can be cut down to around $400\text{mg}/\text{Nm}^3$.

According to Bharat Heavy Electricals (BHEL), technologies exist to reduce NO_x emissions from coal-burning plants to less than $400\text{ mg}/\text{Nm}^3$ by modifying the burners. In fact, a large number of boilers supplied by BHEL since 2000, especially units of size 500 MW and above (85.2 GW), have low NO_x burner design.

Data collected by CPCB suggests that NO_x emissions from coal-based power plants are in the range $150\text{--}600\text{ mg}/\text{Nm}^3$. Although some plants may be under-reporting NO_x emissions, a sizeable capacity could already be meeting the new norms. Low NO_x burning may impact boiler performance, warrant regular maintenance, increase the amount of unburnt carbon, increase slagging in the combustion zone, and accelerate corrosion etc.

Space requirement

Alternate ports for air, called over-fire air (OFA) ports and fuel ports, have to be provided. They require about a metre of space over the burners in the furnace and appropriate space around the boiler and duct.

Time required

Detailed survey and design usually takes two–three months for a 500 MW unit. Component manufacturing according to individual specification takes two–three weeks depending on the manufacturer and complexity of the design. The process of installation, which includes furnace modification by cutting and welding components, laying out ports, ducting etc., takes a month. The power station remains closed during the installation.

Flue gas treatment

To reduce NO_x levels to 100 mg/ Nm³ post-combustion, NO_x control technologies—selective catalytic reduction technology or selective non-catalytic

TABLE 6: TECHNOLOGY COMPARISON

Combustion modification is an easy option, but may not achieve stringent norms

Available technology Parameters	In combustion	Post combustion	
	Combustion modification	Selective non-catalytic reduction (SNCR)	Selective catalytic reduction (SCR)
Variants and measures to control NO _x	<ul style="list-style-type: none"> Low NO_x burner, Wind box modification Various types of “over fire air” (OFA) processes 	Reagent: Anhydrous/ aqueous ammonia or urea	Catalyst type: Plate/ honey comb Reagent: Anhydrous/ aqueous ammonia or urea
Installation cost	0.1–0.15 cr/ MW	0.04 cr/ MW ¹ -0.15 cr/ MW	0.2 cr/ MW ² 0.15 cr/ MW ³ (Hybrid)
Reagent quantity	None	For every tonne NO removal 1.1 tonne ammonia ⁴ is required or two tonne of urea	For every tonne NO removal 1.1 tonne ammonia ⁵ is required or two tonne of urea
Reagent cost	None	Rs 21,000/ tonne (imported technical grade urea)	Rs 2.5-2.7 lac/MW (catalyst replacement – once in three years)
Process of NO _x reduction	Staging of combustion air	Using ammonia: NO reacts with ammonia and oxygen to form nitrogen and water Using urea: NO reacts with urea and oxygen to form nitrogen, water and carbon dioxide.	Nitric oxide/ nitrogen dioxide reacts with ammonia and oxygen to form nitrogen and water
Ammonia slip (excess ammonia, which can potentially react with sulphur in the flue gas and form ammonium bisulphite increasing corrosion of the pre-heater)		Less than 2.5 ppm (Possible to limit less than 0.5 ppm)	
SO ₂ to SO ₃ conversion		Less than 1 per cent	
Mal-distribution or improper mixing		Less than 5 per cent	

Source: NTPC Limited and CSE survey of manufacturers

¹ If base NO_x level less than 400 and target 300 mg/ Nm³.

² If base NO_x level less than 500 and target 300 mg/ Nm³.

³ If base NO_x level less than 450 and target 300 mg/ Nm³.

⁴ 1 mol of nitric oxide reacts with 1 mol of ammonia and ¼ mol of oxygen to produce 1 mol of nitrogen and 3/2 mol of water. molar mass of nitric oxide = 20 and ammonia = 17; nitric oxide: ammonia = 20:17; considering wastage 30% nitric oxide: ammonia requirements = 1:1.1.

⁵ 1 mol of nitric oxide reacts with 1 mol of ammonia and ¼ mol of oxygen to produce 1 mol of nitrogen and 3/2 mol of water. molar mass of nitric oxide = 20 and ammonia = 17; nitric oxide: ammonia = 20:17; considering wastage 30% nitric oxide: ammonia requirements = 1:1.1.

reduction technology—need to be employed. These control technologies split the nitrogen oxide molecules in the flue gas into nitrogen and oxygen with the help of a catalyst or reducing agent (see *Table 6: Technology comparison*).

Selective non-catalytic reduction (SNCR)

SNCR reduces NO_x by reacting urea or ammonia with the NO_x at temperatures of around 900–1,100 °C. Urea or ammonia is injected into the furnace in the post-combustion zone to reduce NO_x to nitrogen and water.

Key advantages and shortcomings

- SNCR technology doesn't require additional space as it basically involves injecting ammonia, urea or a reducing agent into the furnace.
- Capture efficiency of SNCR is only 25–40 per cent.

Selective catalytic reduction (SCR)

SCR utilizes ammonia as a reagent that reacts with NO_x on the surface of a catalyst. The SCR catalyst reactor is installed at a point where the temperature is about 300–390 °C, normally placing it after the economizer and before the air pre-heater of the boiler. The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency.

Key advantages and shortcomings

- Emission reduction of up to 90 per cent can be achieved.
- SCR is installed right after the boiler as the equipment requires high temperature to break the oxides. This increases the requirement of space.
- The power industry is unsure about the effectiveness of SCR for high dust loading (over 90 g/ Nm^3), which is the case in India. According to the power industry, SCR equipment have been working under dust load of less than 60–70 g/ Nm^3 . National Thermal Power Corporation (NTPC) is working on pilot projects that will have a cyclone prior to SCR/ SNCR to bring down the dust to test its suitability for Indian coal.

Time required

Typically, the installation of a 500 MW SNCR system requires about four months. The installation includes ducting work near the fire box and construction of a mixing/ storage tank. The construction of the SCR system consists of an aqueous ammonia storage tank, vaporizer, mixer and catalyst bed. The shutdown time for both the installation of SCR and SCNR is approximately one month.

Conclusions

1. No control measures should be needed for a significant share of the 65 GW capacity installed prior to 2003, which is meeting 600 mg/ Nm^3 norm. Some plants may need burner modification or OFA etc. to meet the norms.
2. The balance 121.3 GW has to reduce emissions below 300 mg/ Nm^3 . Depending on the base level of emissions and technical constraints, these plants will have to opt for installation of either low NO_x burners or, in a few cases SNCR/ SCR, requiring an investment of roughly 0.1–0.15 cr/ MW.
3. For every tonne NO removal, 1.1 tonne ammonia or two tonne of urea is required (see *Annexure*).
4. Ammonia and urea, essential reagents, can be easily sourced.

Mercury

Coal-based thermal power plants are responsible for 80 per cent of the mercury emissions in India. Currently, mercury emissions from Indian coal power stations is in the range of 19–130 $\mu\text{g}/\text{Nm}^3$, depending on mercury content in the coal. To meet the new norms of 30 $\mu\text{g}/\text{Nm}^3$, special abatement devices are not required. Installation of FGD devices capable of absorbing 85–90 per cent of the mercury in flue gas, and injection of activated carbon and halogen bromides can be done to increase mercury capture (for more details see: *Annexure*).

The way forward

Investments

Financing required for capital expenditures to meet the new norms remains a major concern. The cost of pollution control technologies is manageable, however, these could result in some increase in tariff. Given the weak financial health of generating companies (especially the state owned ones), tariff approval would need to be expedited (see *Table 7: Cost of pollution control equipment*).

TABLE 7: COST OF POLLUTION CONTROL EQUIPMENT

SO₂ control will require largest share of the investment

Technology required	Approximate cost (in lakhs/ MW)
ESP upgradation	5–15
FGD	50–60
Partial FGD	25–30
Low NO _x burners/ SNCR/ SCR	10–15

Source: CSE Survey of Manufacturers

Financing mechanism

- The government should consider using the coal cess of Rs 400 per tonne levied on all coal buyers to support the investment through soft loans or other financing mechanisms.
- Generating companies, especially financially stable ones, should be able to raise debt from banks if there is clarity on cost recovery/ tariff increases.

Cost recovery and incentives

- Recovery of costs through tariff hikes must be expedited. Cost benchmarking by CERC, with the aid of CEA, along with a simplified application process should be developed.
- Plants that take a leadership role in being among the first to assess needs, procure and install equipment to meet the new norms need to be given incentives like priority in dispatch.
- Forum of regulators should facilitate standardization of documents and approvals across state emissions reduction credits to aid in tariff hikes petitions.

Compliance with new norms

Pollution control technologies for coal-based power stations are two–three decades old. Industry experts are confident that there is no technical hurdle in complying with the norms, instead economic considerations play a role in what a given plant considers most appropriate.

Particulate matter

- Complying with PM norms by power stations is possible with very few obstacles in terms of investment, technology and timeframe except in very specific cases.
- The alternatives suggested for improving ESP performance include adding

fields, increasing spacing between electrodes, increasing height of the flow section, combination with bag filters, flue gas conditioning, and replacing conventional transformer-rectifier set with high frequency power systems, moving electrode ESPs, low temperature high performance ESPs, etc.

Sulphur dioxide

- Wet limestone-based FGD, having removal efficiency of 99 per cent, is the recommended solution to meet the standard of 200mg/ Nm³. Partial FGD is advised for units which have to meet the 600mg/ Nm³ standard. Between these two options, a vast majority of the fleet installed after 2003 can achieve compliance.
- Space may be a constraint for some plants—e.g. larger than 500 MW units installed prior to 2008. One option is to consider bringing the norms for these units in line with the smaller units (600 mg/ Nm³). This will affect around 15.5 GW of capacity.
- Units older than 25 years could consider technologies such as sorbent injection combined with low sulphur to cut emissions. Some may find it challenging to meet the standard and the best course of action may be expedited retirement, especially given their limited remaining life.

Oxides of nitrogen

- A significant share of the capacity may already be meeting the standards with low NO_x burners or other NO_x abatement in place.
- For units with NO_x emissions, a range of about 600–800 mg/ Nm³ retrofits can be made in the burner systems to reduce NO_x emissions to 300–400 mg/ Nm³.
- It is possible that retrofits may not be sufficient to get some of the units to below 300mg/ Nm³ (norm for plants installed after 2003). On a case-to-case basis, some units—for e.g., the ones located in dense urban areas or highly polluted areas—could be required to install SCR or SNCR, which can bring down NO_x to less than 100 mg/ Nm³. For others, perhaps the NO_x limit may be modified to around 400 mg/ Nm³.

Timelines

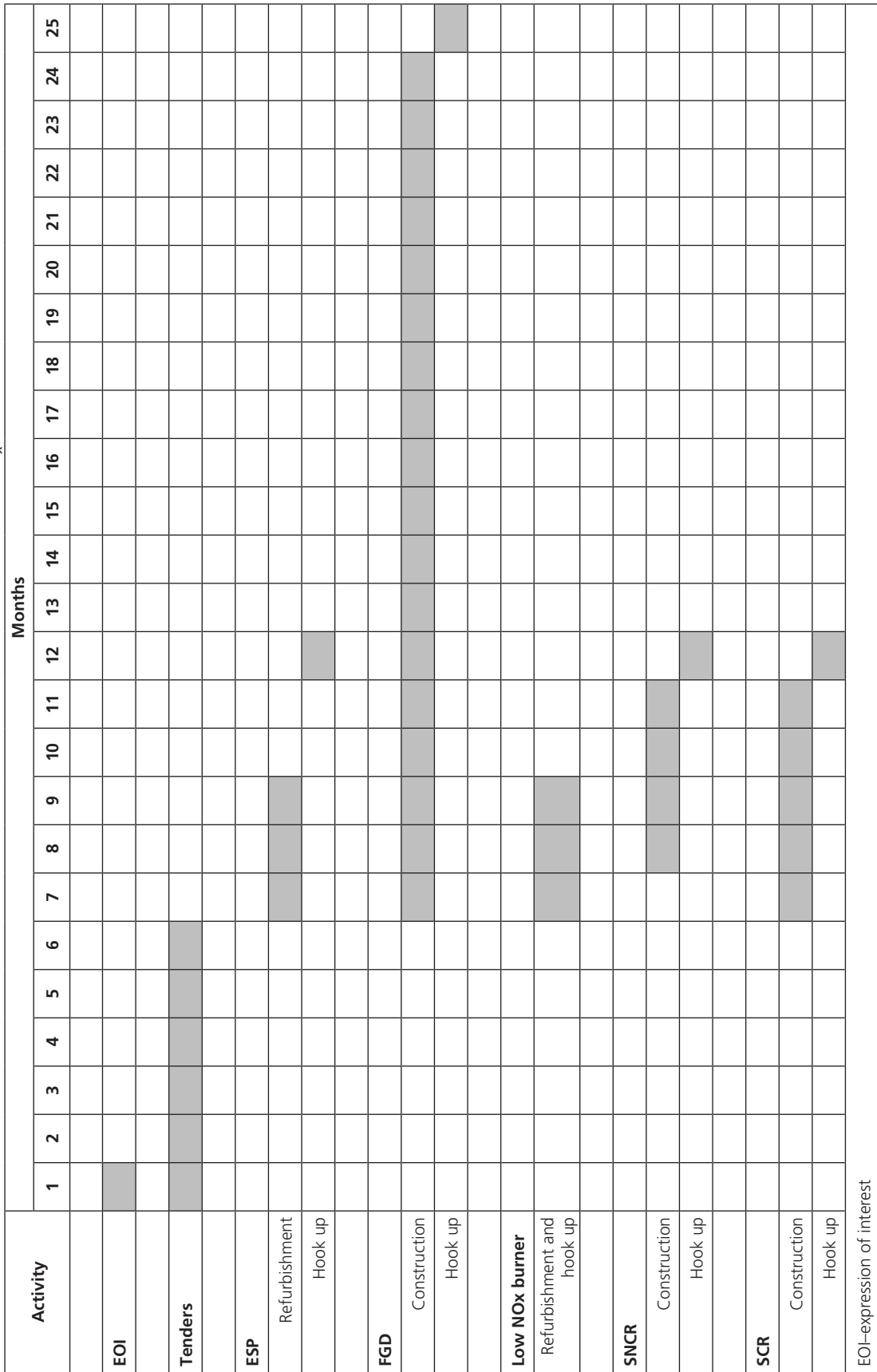
Preliminary survey of pollution control equipment manufacturers indicates that installation should not take more than a year, with shutdown time of the plants less than a month for control of particulate matter and oxides of nitrogen in typical cases. However, installation of FGD units could take a year and half for construction, excluding shutdown time of the plant, which varies between 30–90 days depending on the chimney linings and height (see *Graph 6: Gantt chart*).

Equipment availability

India has approximately 30–40 GW per annum power station component (boiler and turbine) manufacturing capability. The leading power manufacturing companies also have ESP and low NO_x burner manufacturing capabilities. They are also confident of catering to FGD demands. Since the 12th five year plan period, 15–25 GW power station capacity is being added every year in India (see *Table 8: The big five*).

GRAPH 6: GANTT CHART

The retrofit or new installation/ construction of FGD units takes the longest time and low that NO_x burner the shortest time



Note : On case-to case-basis, the timelines will vary depending on technical additionality and plant location. Indicated is typical retrofitting time for a 500 MW unit.

TABLE 8: THE BIG FIVE*

The top five companies can meet two-thirds of coal-based power station components demands; however India imports more than half its components requirement from China

Company	Production capacity in MW
Bharat Heavy Electricals Ltd (BHEL)	20,000
General Electric Power	9,000
Thermax	6,000
Larsen and Turbo (L&T)	5,000
ISGEC Heavy Engineering Company Pvt Ltd	1,000

* Apart from the big five, there are two other groups: pollution control equipment manufacturers like Cethar Ltd, Himenviro, Mazda house, Batliboi etc.; and technology providers like Doosan, Fuel Tech, Clyde Bergmann, Johnson Maithy, Andritz, KC Cottrell, Hammon Cottrell etc. These companies procure 80 per cent of the components required for construction from sub-vendors and the rest are sourced from their manufacturing base outside India. Importing equipment take less than four months as per the manufacturers' claims.

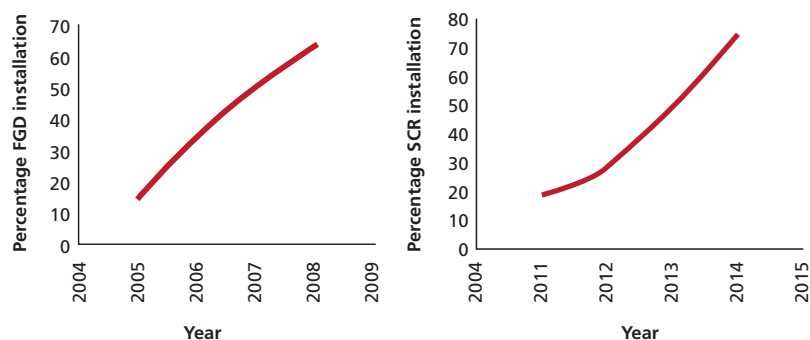
Technology

Major power equipment manufacturing firms have signed patent agreements for SO₂ emission control technologies. Thermax has signed partnership with Marsulex, ISGEC Heavy Engineering Company Pvt Ltd with Amec Foster Wheeler, and Bharat Heavy Electricals Ltd. (BHEL) with Mitsubhusi Hitachi etc. Domestic companies like Transparent Technologies Pvt Ltd have developed indigenous technologies for SO_x, however, they have limited experience of larger installations, NO_x and PM control technology and are mostly indigenous.

Manufacturing companies are confident that pollution control technology options are techno-economically feasible and the capacity will ramp up with demand as happened in China. FGD penetration in China grew from 14 to 63 per cent in three years (2005–08), similarly between 2011 and 2014, de-NO_x equipment installations grew from 18 to 74 per cent (see *Graph 7: Penetration of FGD and SCR in China*).

GRAPH 7: PENETRATION OF FGD AND SCR IN CHINA

China scaled up installation of pollution control equipment in three years



Source: China Electricity Council

ANNEXURE:

Technology options — description

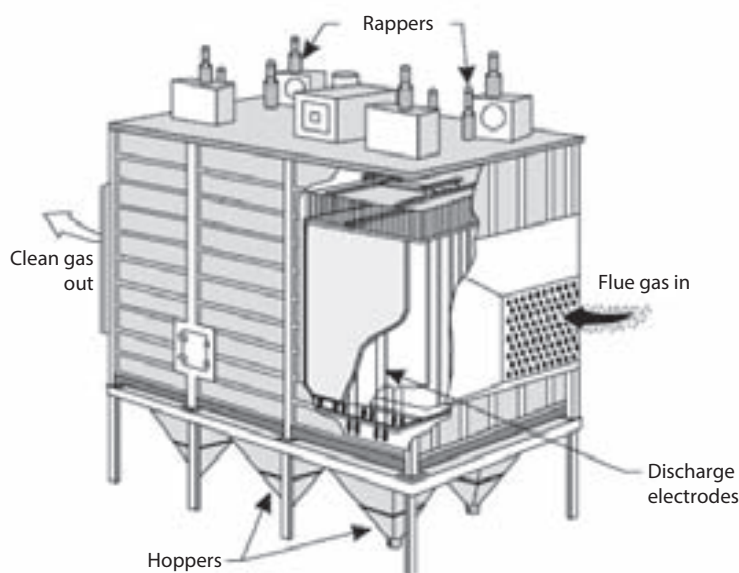
ELECTROSTATIC PRECIPITATORS

Electrostatic precipitators have three major components: the collecting electrodes, discharge electrodes and dust dislodging systems enclosed in a structure called the 'field'. By passing current through the discharge electrodes, dust particles in the flue gas are charged; the charged dust particles move towards the collecting electrodes and stick to them. These dust particles are finally removed by beating the electrodes.

The performance of an ESP depends on several factors: the specific collection area ($\text{sq m}/\text{m}^3/\text{s}$), the duration and volume of the flue gas that comes in contact with the electrode, the voltage used to create electric fields, the way electric current is passed, the resistivity shown by the ash particles to get charged, and the way the collected ash is dislodged (see *Table 1: ESP specifications of coal power stations*).

FIGURE 1: TYPICAL DRY ESP AND ITS COMPONENTS

Over 95 per cent of coal power plants in India have installed dry ESP



Source: United States Environment Protection Agency (USEPA)

TABLE 1: ESP SPECIFICATIONS OF COAL POWER STATION

ESPs in India are designed for high dust load

Inlet dust concentration	40–100 g/ Nm ³
Specific collection area	130–250 m ² / (m ³ / s)
Operational voltage	30–95 kV
Resistivity of dust	10 ⁻¹¹ –10 ⁻¹⁵ ohm/ cm
No. of ESP electrodes	24–32
No. of fields	3–5
Mode of energy	Semi-pulse, intermittent or multi-pulse mode
Designed collection efficiency	More than 99.5 per cent

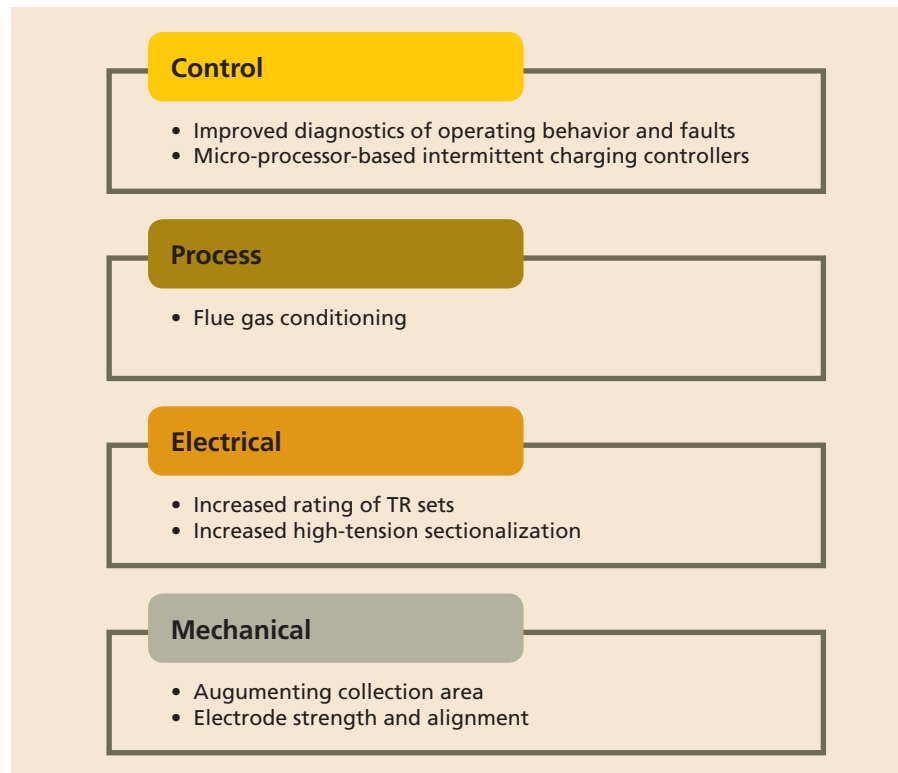
Source: Centre for Science and Environment, 2016

Upgrading electrostatic precipitators: options

ESP performance can be enhanced by process, mechanical, electrical or control changes in the device. The relevant technique is selected depending on the reduction required in dust concentrations. For example, if dust concentrations have to be sharply reduced, say from 500 to 50 mg/ Nm³, then mechanical changes are made; for lesser reduction, say from 75 to 50 mg/ Nm³, process changes may be sufficient, in certain cases combination of the techniques are used depending on the condition of the device.

FIGURE 2: METHODS TO UPGRADE ESPS

Augumenting the collection area is widely used if material improvement is required



1. Controls

Changes in system control are generally the first to be explored since they involve little investment and technical complications.

Improved diagnostics of operating behaviour and faults

The first step is studying ESP performance and deviation from design, reasons for deviation and parameters to be optimized and controlled. For example, the following are a few diagnostic steps:

1. **Check if hopper switches are not bypassed and ash is being effectively dislodged:** PM may entrain in the ESP due to delay in rapping or removal of ash from the hopper. On the other hand, excessive rapping can result in wear and tear of the system, lowering performance. Timely removal of ash from the hopper and proper dislodging is, therefore, important.
2. **Check the temperature of the flue gas for which the ESP was designed, and the flue gas inlet temperature:** Flue gas temperature higher than the design indicates boiler leakages, which result in higher flue gas volumes and temperatures, impacting ESP performance.
3. **Check if seal air systems are properly maintained.**

Intermittent charging

To charge the dust in the flue gas, short duration high voltage current is required. Typically, ESPs are powered by high voltage alternating current (70 kV), supplied at a frequency of 50–60Hz, which is converted to DC power by transformer–rectifier sets in the ESPs to charge dust particles. However, sometimes due to high voltage, not only the dust particles but the molecules in flue gas also get charged. In addition, dust particles also induce flue gas charging. This phenomenon of flue gas getting charged is called back corona effect, which reduces ESP efficiency.

To overcome back corona, switched mode power supply is used, which continually switches the electric fields on and off. If DC current is switched on-off in milliseconds, the technique is called intermittent energizing technique and if it is done in microseconds it is called pulse energizing technique. These energizing methods increase the efficiency of the ESP—intermittent charging has been found to reduce dust emissions by 55–70 per cent.

2. Process

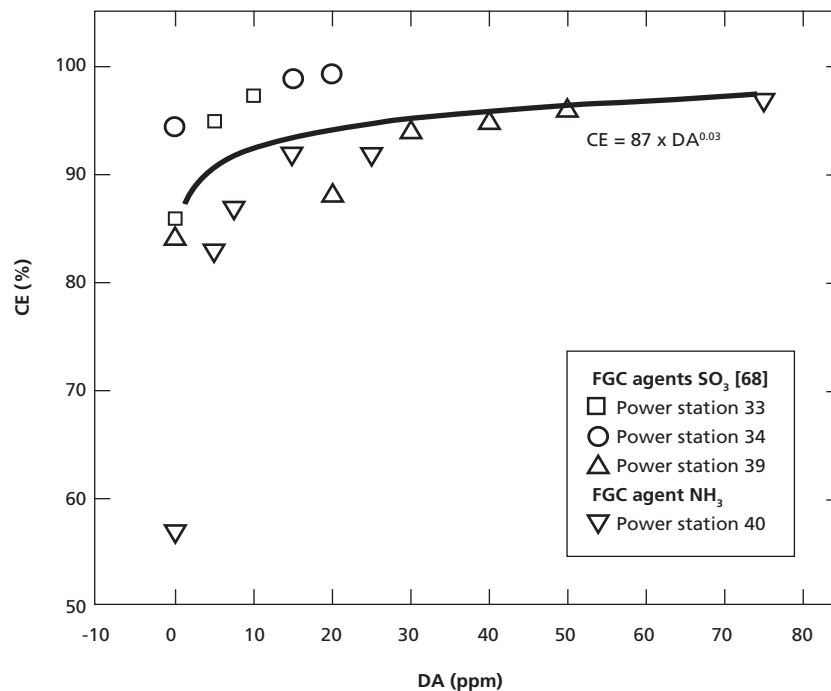
Flue gas conditioning (FGC)

FGC involves injection of chemical additives (viz., SO_3 , H_2SO_4 , ammonium sulphate, ammonium bisulphate, sulphamic acid and ammonia) and/ or water or steam (water fogging) into the flue gas to alter the physical and electrical properties of the dust particles to increase the collection efficiency of the ESP.

Ammonia and SO_3 conditioning are mature. SO_3 conditioning is normally appropriate for ESPs with nominal operating temperatures of 130 to 165 °C. At temperatures above 175 °C, the effect is minimal and injection can actually cause stack emission problems from condensation plumes. SO_3 conditioning increases the resistivity of the ash which improves the collection rate. Ammonia, on the other hand, does not increase the resistivity, however it reduces re-entrainment in the ESP, improving its performance.

GRAPH 1: DOSING AND DUST RESISTIVITY

Dosing with ammonia and SO₃ are popular methods



Source: IIT, Delhi

FGC has been tried in India by power plants like Tata Trombay. Installation of an FGC system involves dismantling and relocating or rerouting existing facilities like steam pipes, cable racks and duct support columns, and strengthening supporting structures to withstand different loads. Additional technical constraints in installation of FGC systems include availability of nearest foundation, presence of ash slurry trenches, possibility of erecting the structure in the limited space around an ESP by employing tower type cranes, and ensuring flow distribution. This option is suitable for removing coarse particles and minor reduction of dust load.

Optimal injection and mixing mechanisms are essential for assured performance. Over injection may lead to fouling, corrosion, clogging, unsalable ash generation etc.

3. Electrical

Electrical modifications involve mere external work and are, therefore, preferable to other methods. In electrical techniques two modifications are common: 1) increasing rating of transformer-rectifier sets upto 120 kV and 2) increasing the number of bus bars in the system—to provide uniform and increased current density. Electrical improvements can achieve greater emissions reduction than FGC.

4. Mechanical

These techniques tend to be the last attempts to improve performance in difficult cases with very high emissions. They require longer time to implement owing to civil engineering work.

Augmenting the collection area

Increasing the collection area of the electrostatic precipitator is the commonly advised upgradation and has been implemented in several Indian power stations. The collection area of an ESP can be augmented by:

1. **Installing additional ESPs in series:** Suggested when the space is available and the area of the ESP can be augmented to increase collection efficiency.
2. **Installing additional ESPs in parallel:** When adding ESPs in series is not feasible due to space constraints, addition of ESPs in parallel is recommended. Parallel ESPs have multiple inlets in contrast to series ESPs, hence they require redesign of flue gas flow and dust redistribution calculations. Multiple inlets in parallel ESPs lead to excess pressure drops. To counter the drop in pressure, additional fans are required, thereby increasing the electricity consumption for the operation of the parallel ESPs.
3. **Adding new internals by increasing the casing height:** When neither parallel and series addition is possible, and improving collection efficiency by increasing specific collection area is a necessity, then this method is suitable. Wider spacing between electrodes are given on increasing the height so that civil foundation load does not increase. To compensate lesser electrode components, higher frequency transformer-rectifier sets are used.

Retaining existing ESPs and adding fields in series at either the inlet or outlet, or increasing the height of the ESP by keeping the length and width of the existing ESPs constant requires additional duct work, enhancing fan capacity and structural load estimates to check if the existing foundation can withstand the load. These modifications require little shutdown time during hook-up of the new system. Rebuilding ESPs by extending casing length at the inlet or outlet, or replacement of ESPs means longer shutdown.

4. **Replacing older ESPs with new ones:** Suggested when drastic improvement is required in collection efficiency and the components of older ESP are degraded.

The retired Koradi units 1-4 and Kothagudem units 1-2 replaced entire ESPs with bigger ones to comply with the environmental standards of 150 mg/ Nm³. The retired Bathinda unit 1 and Indraprastha unit 2 installed additional ESPs in series while MAHAGENCO Parli has experimented with additional ESPs in parallel.

5. **Filling dummy fields:** Dummy fields of an ESP are casings without internals which are installed at either inlet or outlet during the early phase of plant construction. These dummy fields are included to increase the collection area at a later date, if need be.

ESPs at Tuticorin 1-2 (2 x 210 MW), Kothagudem 7-8 (2 x 110 MW), Koradi 5 (1 x 200 MW), Bhusawal 2 (1 x 210 MW), Parli 3 (1 x 210 MW), Nasik 3-5 (3 x 210 MW), Ramagundam 1-3 (3 x 200 MW), Singrauli 1-5 (5 x 200 MW), Ukai 3-4 (2 x 210 MW) and Satpura 7 (1 x 210 MW) had installed dummy fields—these have now been filled. Dummy fields are common in plants which were commissioned between 1960s and 1990s.

Electrode strength and alignment

ESPs come in different configurations and arrangements of electrodes. Electrodes have collecting plates spaced apart by about 250–300 mm. To

improve performance, the spacing can be increased or different configuration of electrodes can be employed or moving electrodes can be used.

- 1. Increasing spacing:** Spacing between electrodes can be widened from 250–300 mm to 400 mm. Existing density distribution in an ESP can be made uniform by introducing wider spacing, improving collection efficiency. Also, increasing spacing would reduce the weight of the ESP internals.
- 2. Moving electrodes:** Another technique is to make the electrodes movable and use brushes fitted in the hopper to scrape dust collected off the plates. The surface of the collecting plate is kept clean and, therefore, there is no back corona. NTPC Rihand is installing moving electrode precipitators (the first such project in the country) to reduce its dust emission from 500 mg/ cu m to 50 mg/ cu m.

BAG FILTERS

Bag filters and houses/ fabric filters is an alternate technology to control PM emissions. Long fiber/ cloth bags are employed to filter dust and are periodically shaken to dislodge dust. Air-to-cloth ratio, ash removal efficiency and the integrity of the structure to withstand high volumes and temperature of flue gas are the key parameters which determine the performance of bag filters.

35 per cent of coal-fired power plants in the US and about 10 per cent of plants in China have installed bag filters or their hybrids. Bag filters installed in combination with an ESP are called a hybrid.

However, bag filters are not very popular among Indian coal power plants because of its failure at an initial pilot scale installation in MAHAGENCO Koradi. The primary concerns at the installation were: reliability of the spray cooling system which was used to cool the flue gas before it entered the bag filters, shrinkage and wear and tear of the bags due to high velocity and particulate concentration of flue gases.

Bag filters are generally recommended for flue gas volumes in the range of 100,000–500,000 Nm³/ h, which is the flow rate in units smaller than 150 MW. Efficiency of bag filters may be up to 99 per cent, but it could drop to 90 per cent if even one of the thousands of bags in the filter gets damaged.

ESTIMATING TYPICAL SPACE REQUIREMENT OF A BAG FILTER

Say 60,000 cu m of flue gas needs treatment and air to cloth ratio is 60 then:

Filtration area required = 60,000/ 60 = 1,000 sq m

A bag of dimension 3 m (l) and 150 mm (d), will have a filtration surface area = $\pi \times d \times l = \pi \times 0.15 \times 3 = 1.413$ sq m

Then number of bags required = 1000/ 1.413 ~ 700 bags

Distance between the two bags is approximately two inches and the number of compartments are decided based on strength required to support the bags. Pulse jet cleaning is preferred.

Polyster bags which cost around Rs 1,000 are often used in power plants but can withstand temperatures of only around 150 °C. Fibre glass bags can withstand temperatures of around 250 °C, however, they are 10 times more expensive than polyester bags. Erecting the bags can be done with cast iron beams (about Rs 500 for a 10 m beam) or mild steel beam (Rs 2,000–5,000). Though cheaper, cast iron easily corrodes, which can damage the bags.

Though bag filters occupy less space they consume more auxiliary energy for operation than ESPs. The flue gas passing through bag filters encounters higher resistance to flow than in an ESP, the difference of pressure between the inlet and outlet of the bag filter (otherwise called the “pressure drop”) is much higher than in an ESP. This pressure drop necessitates a bigger size of fan in bag filters than in an ESP to either push or pull the exhaust gas, resulting in higher auxiliary energy consumption. ESPs give a pressure drop of 1 inch water column and bag filters have a pressure drop of 4 inches water column and consume nearly twice the auxiliary energy than ESPs.

FLUE GAS DESULPHURIZATION UNITS

Flue gas desulphurization is a widely installed and proven technology. In India, however, only 6 GW of coal power capacity—Tata Power Trombay (750 MW), Dahanu Thermal Power Station (500 MW), Udupi Thermal Power Station (1,200 MW), JSW Ratnagiri (1,200 MW), NTPC Vindhyachal stage-V (500 MW), and Adani Power Mundra Ph-III (1,980 MW)—have installed FGD units. Two of these installations, Udupi and Dahanu, were by Ducon and the rest were by Alstom (see *Table 2: FGD footprint*)

FGD technologies are well established: Till date, over 40 per cent of worldwide coal capacity has installed FGD. FGD technologies can be classified as once-through and regenerable, depending on how sorbent is treated after

TABLE 2: FGD FOOTPRINT

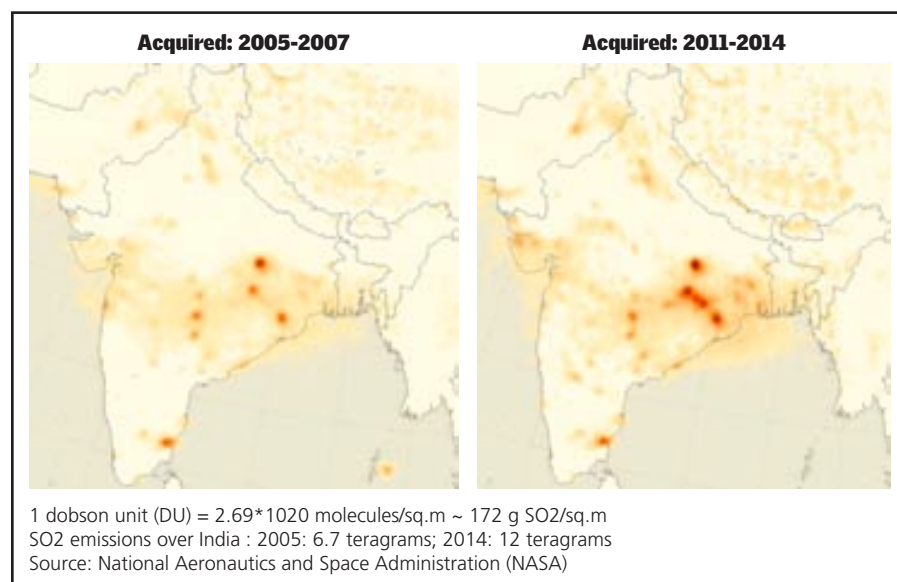
A comparison of resources used in existing FGD units

	Tata Trombay	Reliance Dahanu	Udupi thermal power station	Adani Mundra UMPP	JSW Ratnagiri	NTPC Vindhyachal stage V
FGD connected plant's capacity (MW)	750	500	1,200	1,980	1,200	500
Type of FGD	Seawater wet FGD	Seawater wet FGD	Limestone-based FGD	Seawater wet FGD	Seawater wet FGD	Limestone-based FGD
Area of construction (sq m/ acres)	7,200	Data not available	10,000	1,500 (scrubber alone)	Data not available	10,000–20,000
Water consumption (cu m/ year)	14,773,000	87,600,000–105,120,000	306,600–350,400	125,000–140,000	Data not available	613,200–876,000
Auxiliary power consumption (per cent)	1–1.5	1.25	0.5	1.5	0.5–1.5	1.1
Reagent used	Seawater	Seawater	Limestone	Seawater	Seawater	Limestone
Reagent consumption in kg/ hr	–	–	–	–	–	6,250

Source: Centre for Science and Environment, 2016

MAP 1: IMAGES FROM AURA SATELLITE SHOWING INCREASING SULPHUR DIOXIDE CONCENTRATION OVER INDIA

India's ambient sulphur dioxide concentration has doubled in seven years



it has absorbed SO₂. In once-through technologies, the SO₂ is permanently bound by the sorbent and is disposed of as a waste or utilized as a by-product (e.g., gypsum). In regenerable technologies, the SO₂ is released from the sorbent during the regeneration step and may further be processed to yield sulfuric acid, elemental sulfur, or liquid SO₂. Based on FGD technologies that have an established record, it is clear that regenerable FGD processes are being used only marginally because of high costs. Wet and dry FGD are popular.

Wet FGD: Wet scrubbers are capable of high rates of SO₂ removal. In a wet FGD system, lime or limestone slurry reacts with the SO₂ in the flue gas in a large absorber vessel to capture SO₂. Limestone is more reactive than lime and offers potential for higher reductions at a somewhat lower cost. As a result, limestone-forced oxidation wet scrubber technology is the most widely used (see *Box: The lime cycle*).

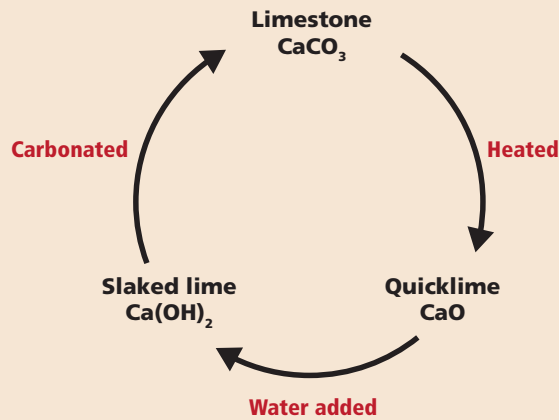
Typically, wet FGD stations have a limestone crushing station and slurry preparation unit occupying approximately a space of about 6–15 sq m/ MW. The slurry is pumped and sprayed in the absorber chamber from the top and flue gas passes out from the bottom. In the absorber chamber, SO₂ is removed by both absorption and reaction with the slurry. Reactions initiated in the absorber are completed in a reaction tank, which provides retention time for finely ground limestone particles to dissolve and to react with the dissolved SO₂. For every kg of SO₂ removal about 1.5 kg of limestone is required.

Spent sorbent from the absorber chamber is dewatered in cyclones/ gravity filters, etc. and disposed.

The process variables which affect the performance of wet FGD include: flue gas flow rate, liquid-to-gas ratio (L/G), pH, flue gas SO₂ concentration, solids concentration and retention time.

THE LIME CYCLE

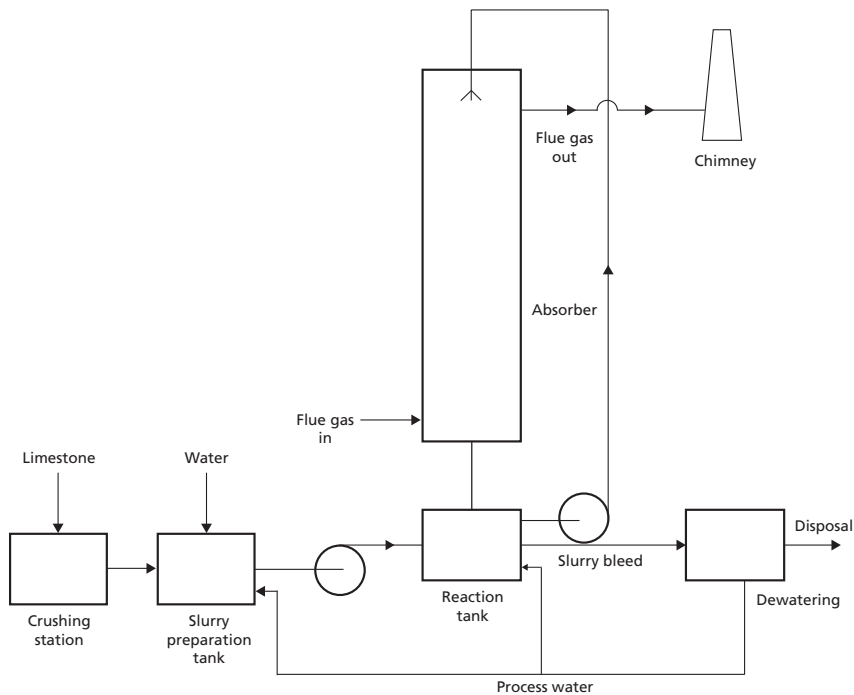
Limestone is the unprocessed mineral from mines, while lime is a reagent obtained by processing limestone with heat to drive away the carbon in the mineral. Since lime is processed by heating using fuel, it is more expensive than limestone.



Source: Peter Bell, 2013

FIGURE 3: LAYOUT OF A WET FGD SYSTEM

State-of-the-art wet FGD systems are capable of providing very high levels of SO₂ removal—on the order of 98 per cent or more



Source: United States Environmental Protection Agency (USEPA)

Seawater FGD: Seawater process utilizes the natural alkalinity of seawater to neutralize SO_2 . The chemistry of the process is similar to wet FGD, except that limestone comes completely dissolved with the seawater there is no dissolution or precipitation of solids. Seawater is alkaline by nature, and has a large neutralizing capacity with respect to SO_2 . The absorption of SO_2 takes place in the absorber, where seawater and flue gas are brought into close contact in a countercurrent flow.

Sulfate is a natural ingredient in seawater, and typically there is only a slight increase of sulfate in the discharge. This increase is within variations naturally occurring in seawater. However, since SO_2 scrubbing introduces a discharge to the ocean, it is necessary to make an assessment based on local conditions, which includes: effluent dilution and dispersion calculations, description of effluent, comparison of effluent data with local quality criteria, description of local marine environment, and evaluation of possible effects from the discharge. High chloride concentrations, characteristic of systems using seawater, result in a requirement for construction materials with increased corrosion resistance.

Dry FGD: Dry FGD systems use quick or slaked lime as sorbent. In dry FGD, SO_2 -containing flue gas comes into contact with an alkaline sorbent and SO_2 is precipitated out as dry waste with handling properties similar to flyash.

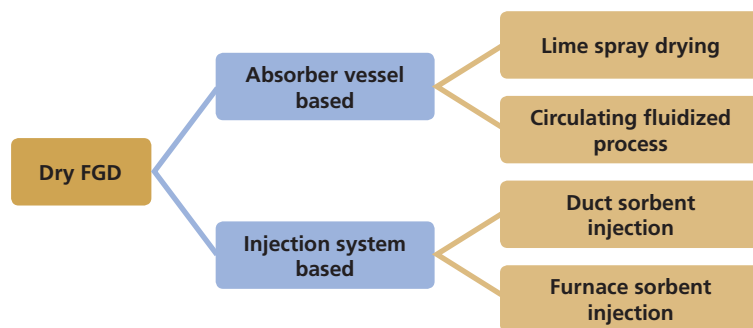
Since the sorbent—quick lime or lime—is pre-processed and is in powdered form, dry FGD does not require a crushing unit. The sorbent can be delivered to flue gas in an aqueous slurry form—lime spray drying process (LSD)—or as a dry powder—duct sorbent injection process (DSI), furnace sorbent injection process (FSI), and circulating fluidized bed process (CFB).

Based on whether a dedicated absorber vessel is required for the sorbent to react with SO_2 , the Dry FGD system can be further subdivided.

Absorber vessel-based dry FGD: The LSD and the CFB require dedicated absorber vessels for sorbent to react with SO_2 , while with DSI and FSI new hardware requirements are limited to sorbent delivery equipment. Hence LSD/CFB systems are slightly more expensive than DSI and FSI. In dry processes, sorbent re-circulation is used to increase its utilization. CFB systems are an evolution of LSD and are more popular.

FIGURE 4: TWO TYPES OF DRY FGD SYSTEM

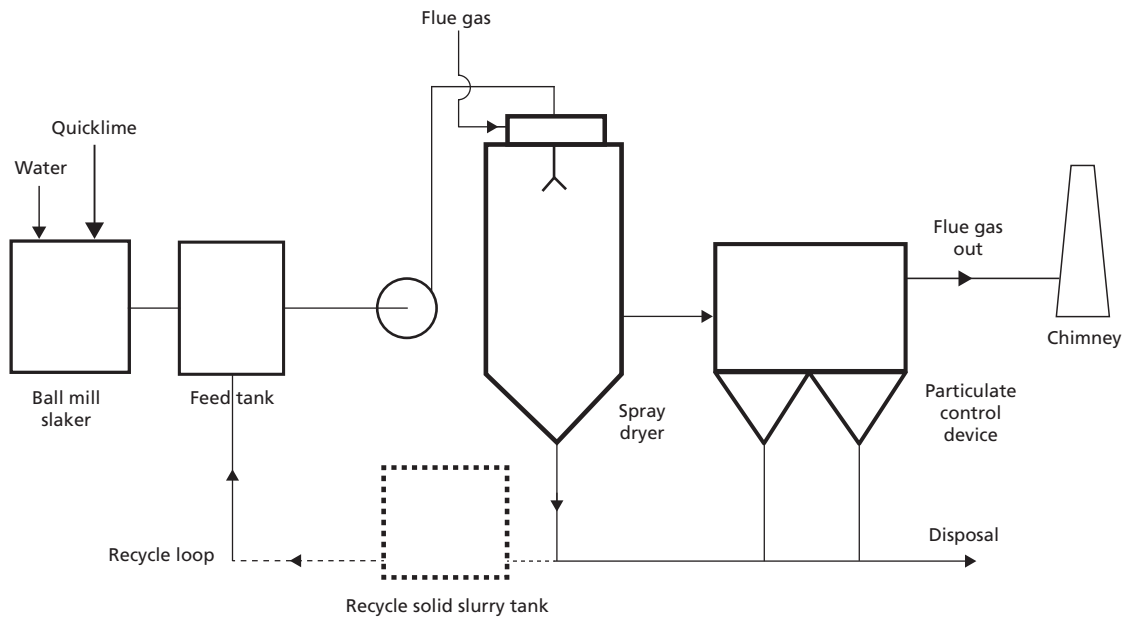
Dry FGD with injection systems requires the least capital investment



Source: Centre for Science and Environment, 2016

FIGURE 5: LAYOUT OF LIME SPRAY DRY FGD SYSTEM

The process generates waste that can not be reused



Source: United States Environmental Protection Agency (USEPA)

1. Lime spray dry FGD system: In the LSD process, freshlime slurry is prepared in a slaker. Rotary atomizers or two-fluid nozzles are used to finely disperse lime slurry into flue gas. Based on stoichiometry, a kg of SO₂ removal requires 0.75 kg of quick lime. Simultaneous heat and mass transfer between alkali in a finely dispersed lime slurry and SO₂ in the flue gas results in a series of reactions and drying of process waste. The dry reaction product solids are collected at the bottom of the spray-dryer. The remaining solids, suspended in the flue gas, travel to the ESP. In order to increase sorbent utilization, part of the dry solids from the bottom of the spray-dryer and the particulate collector's hopper are sent to the recycle solids slurry tank.

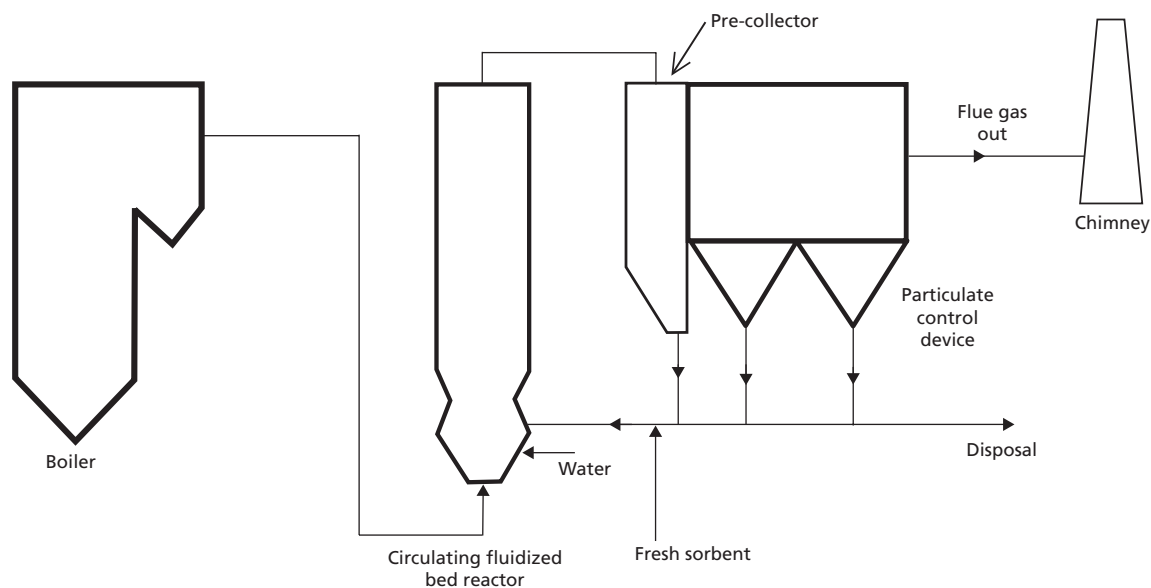
2. Circulating fluidized bed dry FGD systems: In the CFB system, slaked lime is kept in a fluidized state. The fluidization is enabled by passing flue gas upwards through a bed of sorbents.

CFB provides a long contact time between the sorbent and flue gas, the flue gas laden with reaction products then flows to a particulate control device. Some of the particulate matter catch is re-circulated into the bed to increase the utilization of the sorbent, while the remaining fraction is sent to disposal.

Injection systems-based dry FGD system: Though this is the least expensive technology, it has not been widely commercialized. These systems require intricate design and fabrication. They also have limitations in SO₂ removal efficiencies. However, these systems can be useful for plants which are approaching end of their life cycle, and have loose standards to comply with (600 mg/ Nm³).

FIGURE 6: LAYOUT OF CIRCULATING FLUIDIZED BED DRY FGD SYSTEMS

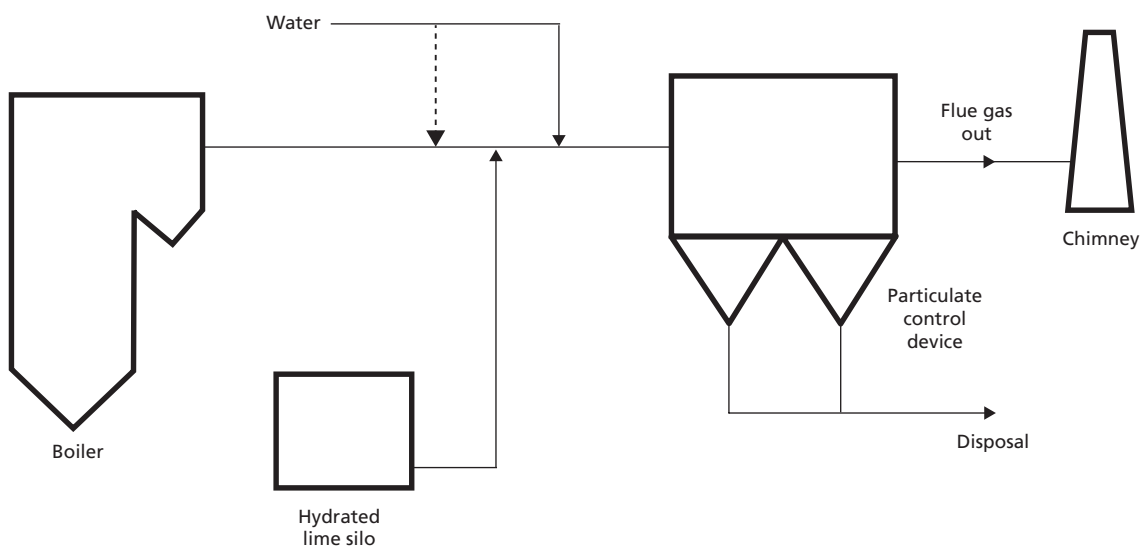
Efficient; since it re-circulates a portion of the particulate matter



Source: United States Environmental Protection Agency (USEPA)

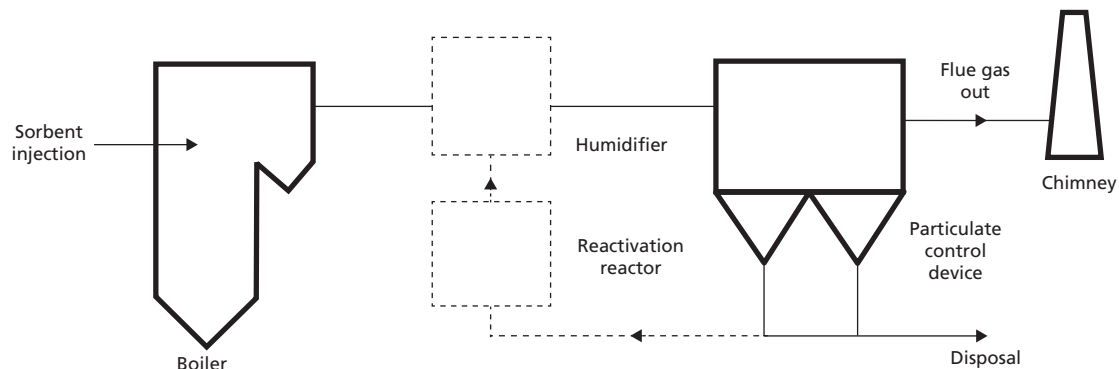
FIGURE 7: LAYOUT OF DUCT SORBENT INJECTION DRY FGD SYSTEM

Costs less because it does not require a scrubber



Source: United States Environmental Protection Agency (USEPA)

1. Duct sorbent injection dry FGD system: In this system, hydrated lime sorbent is injected into the flue gas downstream in the boiler's air pre-heater. The injector positions are optimized to maximally promote suspension of the sorbent particles.

FIGURE 8: LAYOUT OF FURNACE SORBENT INJECTION DRY FGD SYSTEMS*Cheap, but not many working examples exist*

Source: United States Environmental Protection Agency (USEPA)

2. Furnace sorbent injection dry FGD system: In this process, dry sorbent is injected directly into the furnace in the optimum temperature region above the flame. As a result of high temperature (approximately 1,000 °C), sorbent particles decompose and becomes porous solids which aids in absorption of SO₂ and removal.

OXIDES OF NITROGEN

Nitrogen in fuel and air used for combustion reacts with oxygen in the combustion chamber at high temperatures to form oxides of nitrogen. Formation of oxides of nitrogen can be controlled by using low NO_x burners or staged air combustions/over-fire air/ secondary over-fire air supply or through flue gas treatment after combustion.

LOW NO_x BURNERS

These are basically systems which assist in the atomization of the fuel and regulate flow rate of air and fuel for efficient combustion. Boilers in the Indian coal fired power plants are mostly tangentially fired with burners located along the corners. The number of burners in a boiler depends upon the number of bawl mills or coal crushing units available at the coal power plant. For instance, a 210 MW coal power plant in India generally has six bawl mills with four coal pipes emanating from each bawl mill, therefore, twenty four pulverized burners—six coal burners on each corner of the unit—are configured.

Low NO_x burners are designed to curb formation of oxides of nitrogen in the boiler by primarily modifying the flame area of the individual burner as reduction zone instead of the whole combustion chamber. The primary characteristics of these burners are – intensive and early pyrolysis; ignition of the already gasified volatile matter directly at the burner in a high-fuel but air deficiency zone; defined, staged and thus delayed air supply to the fuel products; uniform distribution of fuel and air in the related cross sections to achieve uniform flame spreading; delayed injection of tertiary air etc.

OVER-FIRE AIR SUPPLY

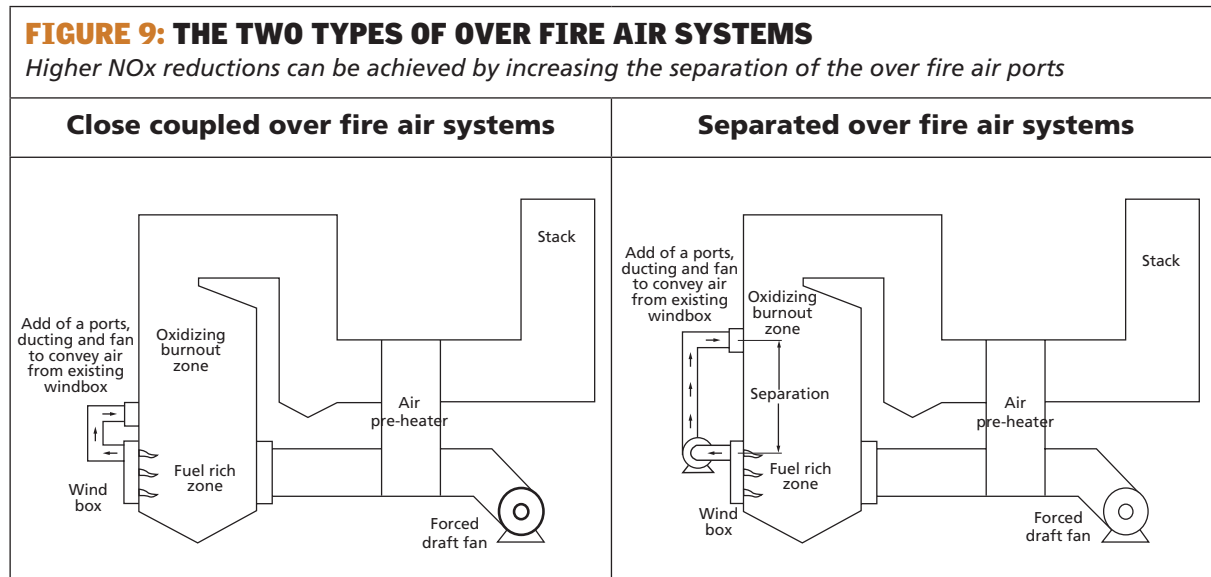
This technique involves supplying about 10–20 per cent of combustion air flow through over-fire air ports located at the highest elevation of the burners in the furnace. The shortage of air to burn fuel in the combustion zone (called fuel richness) limits nitrogen oxide formation. However, carbon monoxide generation is unavoidable. The combustion of the carbon monoxide produced is completed using air supplied by the over-fire air (OFA) ports.

Types: Depending on the position of the air injectors relative to the combustion zone, two types of over-fire air port systems are available—close coupled over-fire air (COFA) and separated over-fire air (SOFA) systems, providing NO_x reductions of 30–50 and about 40–60 per cent respectively. The effectiveness of over-fire air systems depends on adequate mixing of the injected air with the primary combustion products. The port location, number, spacing, geometry, pressure drop and furnace dimensions all must be considered in designing an OFA system. Different levels of the systems have been commercialized. Low NO_x concentric system level III (LNCF level III) is the more advanced technology in the market. OFA and low NO_x burners are often used in combination.

SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR)

These systems convert oxides of nitrogen into diatomic nitrogen and water with the aid of a catalyst and gaseous reducing agent, typically anhydrous ammonia, aqueous ammonia or urea, which sometimes is added to the flue gas or adsorbed onto the catalyst. Carbon dioxide is an additional reaction product when urea is used as the reducing agent. Selective Catalytic Reduction System can remove over 90 per cent of nitrogen oxides.

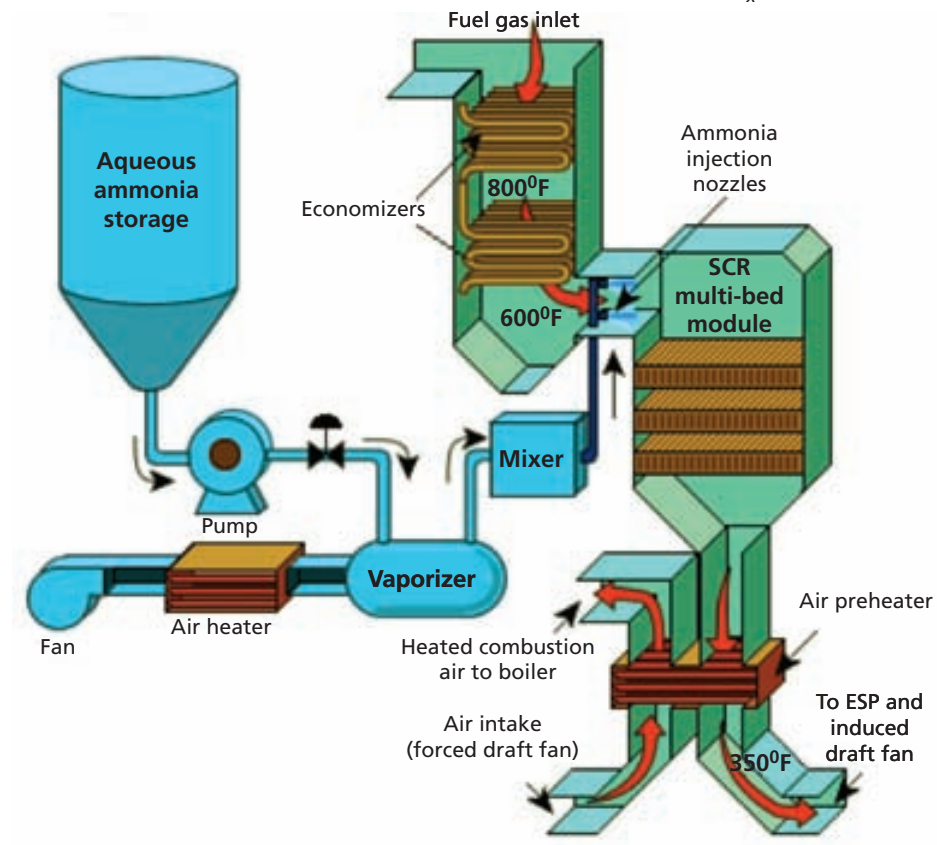
The system is installed between the outlet of the boiler economizer and inlet of air pre-heater as it effectively operates in the temperature range 320–400 °C. It consists of a mixing and dosing system, and a catalytic reactor.



Source: United States Environmental Protection Agency (USEPA)

FIGURE 11: LAYOUT OF SELECTIVE CATALYTIC REACTOR SYSTEM

SCR systems are capable of achieving greater than 90 per cent NO_x removal



Source: NTPC Limited

The key to the SNCR process is optimization of reagent injection with the flue gas within a specific temperature window. For urea, this window is approximately 1,800 °F–2,100 °F (982 °C–1,149 °C); for ammonia, is 1,600 °F–1,800 °F (871 °C–982 °C). The temperature window can be effectively shifted to a lower range by the co-injection of chemicals such as hydrogen with ammonia.

AMMONIA HANDLING

Ammonia—bulk storage

Bulk storage of ammonia is done in vessels manufactured by the Petroleum and Explosives Safety Organization (PESO) approved fabricators. PESO approved fabricators follow the design approved by code (IS 2825 or ASME Section VIII Div. 1) or the standards approved by Chief Controller of Explosives (CCE), Nagpur to manufacture these vessels.

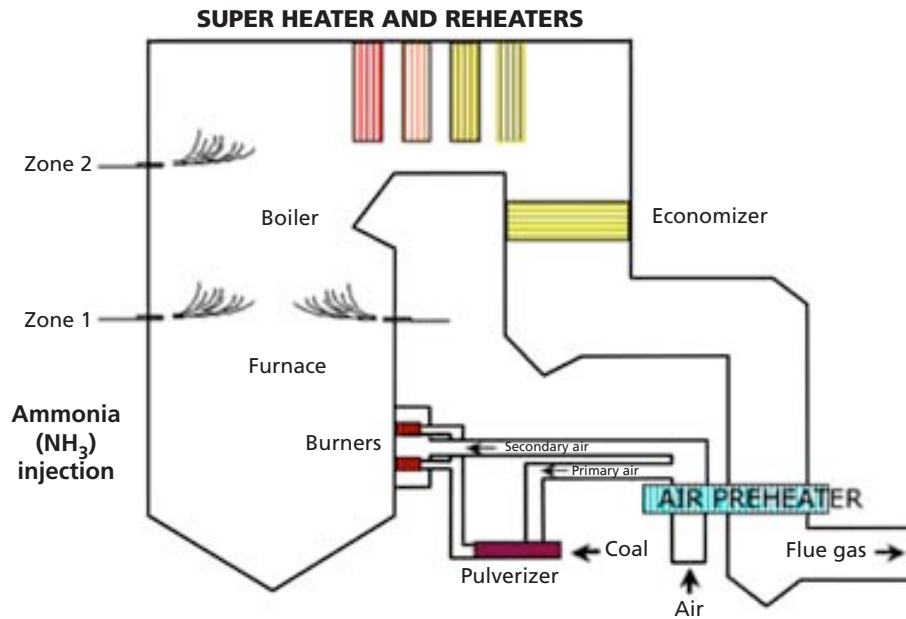
Type of vessels

According to the quantity and vapour pressure held by these vessels, there are two kinds of vessel for bulk storage of ammonia,

- Horton spheres—used to store very large quantities of ammonia in liquid state with vapour pressure in fertilizer manufacturing plants.
- Pressure vessels—used to store comparably lower quantity of liquid gas (more than 1,000 litres).

FIGURE 12: SELECTIVE NON CATALYTIC REDUCTION SYSTEMS

SNCR can remove 40–50 per cent nitrogen oxides



Source: NTPC Limited

Storage license

The storage of ammonia in bulk requires license from Static and Mobile Pressure Vessels (SMPV) (U) Rules, 1981. Application should be made to the CCE, under Rule 49 of SMPV (U) Rules, 1981 for obtaining the storage license. The processing time of approval is generally a week in typical cases, according to the PESO office.

Safety precautions

The following safety precautions are recommended for bulk storage of ammonia:

1. **Fencing**—pressure vessels should be installed in isolated places with a 1.8 metre high fencing.
2. **Enclosure walls**—vessels should be installed within enclosure walls.
3. **Buffer zone**—the minimum distance between the wall and vessel will be the diameter of the vessel or five metres, whichever is less. Safety distance provided to vessels and fill points and other equipments should be strictly as per approved plan.
4. **Monitoring and tests**—periodic hydrostatic tests should be done once every two years by CCE approved competent persons. Toxic gas sensors with hooter alarms should be installed. Flame proof electric fittings should always be tamper-proof.
5. **Emergency plans**—on-site and off-site emergency plan should be prepared and followed meticulously. Local administration should endorse the plans as per Manufacture, Storage and Import of Hazardous Chemical Rules, 1989.

CONTROL OF MERCURY

Mercury is naturally present as a trace metal with concentrations varying from source to source in the range of 0.15–5.27 mg/ kg. When coal is combusted, around 58 per cent of mercury is released from the stacks in gaseous form, 2.5 per cent in particulate form, around 32.5 per cent goes into the ash, while the remaining 7 per cent cannot be accounted for. The stack emissions of mercury can be either in elemental (60–90 per cent) or oxidized (10–40 per cent) form.

Researchers have demonstrated that some degree of co-benefit in mercury control can be achieved with air pollution control devices installed for removing NO_x , SO_2 and particulate matter from coal-fired power plants' combustion flue gases. However, the capture of mercury across these devices can vary significantly based on coal and flyash properties (including unburned carbon), and configuration of the device etc., with the level of control ranging from zero to more than 90 per cent. In addition, the following technologies are available to limit mercury emissions:

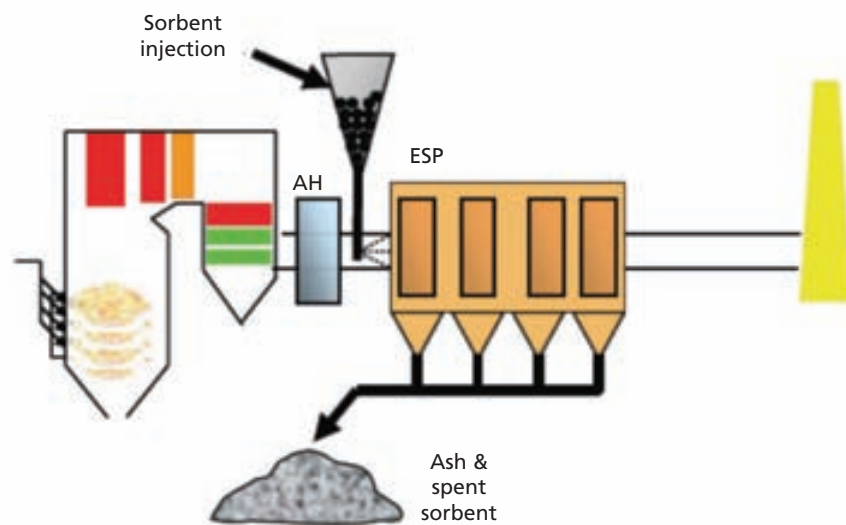
Bromide salt addition/ halogen addition: The least expensive technology for controlling mercury is bromine salt additives. However, these require a scrubber. Halogen (bromine) addition to flue gas increases oxidized mercury that is easier to capture in a downstream scrubber or in a PM control device.

Activated carbon injection: Particles of activated carbon are injected into the exit gas flow, downstream of the boiler. The mercury attaches to the carbon particles and is removed in a traditional particle control device.

However these technologies would not be required to meet the new norms.

FIGURE 13: ACTIVATED CARBON INJECTION

Effective in mercury control



(AH—air handler; ESP—electro static precipitator)

Source: Feeley *et al.*, 2005, Field Testing of Mercury Control Technologies for Coal-Fired Power Plants, DOE/NETL Mercury R&D Program Review, p 3

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