

Environmental issues and challenges of flue gas desulfurization plants in India

Introduction

International awareness of environmental concerns has been increasing in recent years as economists forecast explosive growth around the world. Such predictions highlight the importance of minimizing the impact of increased air, water, and solid waste pollutants. One area that has received a considerable amount of attention is the concern about the potential for acid rain that results from the generation of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) during the combustion of fossil fuels. Particularly notable are the programmes on flue gas desulfurization (FGD) technologies that have been ongoing in a number of countries for several years. Seeking to improve the effectiveness of SO₂ emission control, FGD research and development has progressed to the point that an array of processes are available to cover a broad range of site-specific, technical, and economic considerations.

The Government of India, Ministry of Environment, Forest and Climate Change (MoEFCC) vide its Notification No.S.O.3305 (E) dated 7.12.2015 notified the Environment (Protection) Amendment Rules, 2015 (Amendment Rules, 2015) amending/introducing the standards for emission of environmental pollutants to be followed by the "Thermal Power Plants". By the said amendment rules, all existing thermal power plants are required to meet the modified/new norms within a period of two (2) years from the date of the Notification. By the said amendment, MoEFCC has –

- (a) Revised emission parameters of particulate matter ("PM").
- (b) Introduced new parameters qua sulphur dioxide (SO₂), oxides of nitrogen (NO_x) and Mercury (Hg).
- (c) Directed all thermal power plants with once through cooling ("OTC") to install cooling tower ("CT"); and
- (d) Introduced/prescribed a limit to the amount of cooling water to be used per unit. The submissions of the petitioner are as under:

As per the amendment rules, 2015, the thermal generating

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stations are required to comply with the revised environmental norms within 2 years of the date of publication of the above notification dated 7.12.2017. The revised norms as applicable for project are summarized in Table 1:

Further, the revised environmental norms issued by MoEF and CC also tightened the norms for water consumption which are given below:

- All plants with once through cooling (OTC) shall install cooling tower (CT) and achieve specific water consumption of 3.5m³/MWh within 2 years of notification.
- All existing CT based plants shall reduce specific water consumption up-to maximum of 3.5m³/MWh within a period of 2 years of notification.
- New plants to be installed after 1st January 2017 shall have to meet specific water consumption of 2.5m³/MWh and achieve zero water discharge.

The new standards are aimed at reducing emission of PM10, sulphur dioxide and oxide of nitrogen, which will, in turn, help in bringing about an improvement in the ambient air quality in and around thermal plants. The technology employed for the control of proposed limit of sulphur dioxide SO₂ and nitrogen oxide NO_x will also help in control of mercury emission as a co-benefit.

Limiting the use of water in thermal power plant will lead to water conservation as thermal power plant is a water-intensive industry. This will also lead to reduction in energy requirement for pumping water. There are major challenges and issues associated with implementation of new environmental norms, such as:

- Present available technological solutions need to be adopted to suit Indian conditions.
- The legal framework has to be adopted according to new technical solutions.
- Retrofit cost and its impact on tariff has to be minimized.
- Time schedules for implementation of new environment norms requires optimum project management. In order to meet the above challenges, it is necessary to deliberate these issues for control of pollution in thermal plants based on international experiences and available

TABLE 1

Emission parameter	TPPs (units) installed before 31st December, 2003	TPPs (units) installed after 31st December 2003 and upto 31st December 2016	TPPs (units) to be commissioned after 1st January 2017
Particulate matter	100mg/Nm ³	50 mg/Nm ³	30 mg/Nm ³
Sulphur dioxide (SO ₂)	600 mg/Nm ³ for units less than 500 MW capacity 200 mg/Nm ³ for units 500MW and above capacity	600 mg/Nm ³ for units less than 500 MW capacity 200 mg/Nm ³ for units 500 MW and above capacity	100 mg/Nm ³
Oxides of nitrogen (NO _x)	600 mg/Nm ³	300 mg/Nm ³	100 mg/Nm ³ further, the revised

technological options for compliance of new environmental norms by thermal plants.

India second largest emitter of SO₂ in the world

It is imperative to note that images released by NASA's Aura satellite show doubling of sulphur dioxide concentrations over India in 2012 when compared to 2005. Emission inventory estimates published by Zifeng Lu, scientist at Argonne National Laboratory and the US Environmental Protection Agency confirm India as the second largest emitter of SO₂ in the world, a significant share of which is produced by coal-based power plants. Though Indian coal is low in sulphur content, its calorific value is also low. Therefore, the power plants use relatively large quantity of coal per unit of electricity generated. As a result, total SO₂ emissions by Indian plants are high.

Sulfur oxides

Pollution from coal-fired power plants comes from the emission of gases such as CO₂, NO_x and SO₂ into the atmosphere. These gases react with the atmospheric air to create acidic compounds such as H₂SO₃, HNO₂, H₂SO₄ and which precipitate as rain, hence it is called acid rain. Exposure to particulate matter 2.5 increases the risk of death from heart disease, respiratory diseases and lung cancer.

It is important to remember that the acidity of any solution is measured in pH (potential hydrogen) scale ranging from 1 to 14, with pH 7 taken as neutral. pH values higher than 7 are considered alkaline (the pH of baking soda is eight); pH values lower than 7 are considered acidic (the pH of lemon juice is two). Also remember that the pH scale is a logarithmic measure which means that every pH change of one ($\Delta\text{pH}=1$) is a 10-fold change in acid content. Therefore, a decrease from pH 7 to pH 6 is a tenfold increase in acidity; a drop from pH 7 to pH 5 is a 100 fold increase in acidity; and a drop from pH seven to pH 4 is a 1000-fold increase. NO₂ changes vegetation. NO_x and SO_x contribute to the growing respiratory disease.

Flue gas desulfurization

FGD is a technology used to remove sulphur dioxide (SO₂) from the exhaust flue gases of fossil fuel power plants. Fossil fuel power plants burn coal or oil to produce steam for steam

turbines, which in turn drive electricity generators. Sulphur dioxide is one of the elements forming acid rain. Tall flue gas stacks disperse emissions by diluting the pollutants in ambient air and transporting them to other regions.

As stringent environmental regulations regarding SO₂ emissions have been enacted in many countries, SO₂ is now being removed from flue gases by a variety of methods. The below is among the common methods used:

- Wet scrubbing using a slurry of alkaline sorbent, usually limestone or lime, or seawater to scrub gases;
- Spray-dry scrubbing using similar sorbent slurries;
- Wet sulfuric acid process recovering sulfur in the form of commercial quality sulfuric acid;
- SNO_x flue gas desulphurification removes sulphur dioxide, nitrogen oxides and particulates from flue gases;
- Dry sorbent injection systems.

For a typical coal-fired power station, FGD will remove 95 per cent or more of the SO₂ in the flue gases.

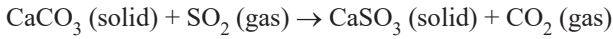
FGD Chemistry

Most FGD systems employ two stages: one for fly ash removal and the other for SO₂ removal. Attempts have been made to remove both the fly ash and SO₂ in one scrubbing vessel. However, these systems experienced severe maintenance problems and low removal efficiency. In wet scrubbing systems, the flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator or a wet scrubber, and then into the SO₂ absorber. However, in dry injection or spray drying operations, the SO₂ is first reacted with the sorbent and then the flue gas passes through a particulate control device.

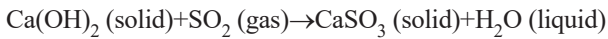
Another important design consideration associated with wet FGD systems is that the flue gas exiting the absorber is saturated with water and still contains some SO₂. These gases are highly corrosive to any downstream equipment such as fans, ducts, and stacks. Two methods that can minimize corrosion are: (1) reheating the gases to above their dew point, or (2) choosing construction materials and design conditions that allow equipment to withstand the corrosive conditions. Both alternatives are expensive, and engineers designing the system determine which method to use on a site-by-site basis.

SCRUBBING WITH A BASIC SOLID OR SOLUTION

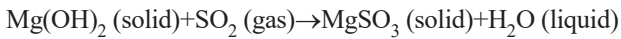
SO₂ is an acid gas and thus the typical sorbent slurries or other materials used to remove the SO₂ from the flue gases are alkaline. The reaction taking place in wet scrubbing using a CaCO₃ (limestone) slurry produces CaSO₃ (calcium sulfite) and can be expressed as:



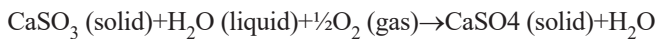
When wet scrubbing with a Ca(OH)₂ (lime) slurry, the reaction also produces CaSO₃ (calcium sulfite) and can be expressed as:



When wet scrubbing with a Mg(OH)₂ (magnesium hydroxide) slurry, the reaction produces MgSO₃ (magnesium sulfite) and can be expressed as:



To partially offset the cost of the FGD installation, in some designs, the CaSO₃ (calcium sulfite) is further oxidized to produce marketable CaSO₄·2H₂O (gypsum). This technique is also known as forced oxidation:



A natural alkaline usable to absorb SO₂ is seawater. The SO₂ is absorbed in the water, and when oxygen is added reacts to form sulfate ions SO₄⁻ and free H⁺. The surplus of H⁺ is offset by the carbonates in seawater pushing the carbonate equilibrium to release CO₂ gas:

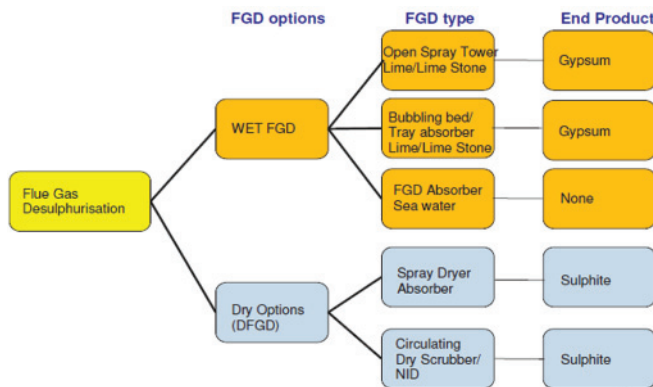
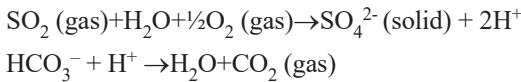


Fig.1: Types of FGD system

Theory of operation

The FGD or SO₂ scrubbing process typically uses a calcium or sodium based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the duct. The SO₂ is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

Scrubbers are classified as “once-through or “regenerable”, based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a by-product. Regenerable systems recycle the sorbent back into the system. At the present time, regenerable processes have higher costs than once-through processes; however, regenerable processes might be chosen if space or disposal options are limited and markets for by-products (gypsum) are available (Cooper, 2002). In 1998, approximately 3% of FGD systems installed in the US were regenerable.

Both types of systems, once-through and regenerable, can be further categorized as wet, dry, or semi-dry. Each of these processes is described in the following sections.

Wet systems

In a wet scrubber system, flue gas is ducted to a spray tower where aqueous slurry of sorbent is injected into the flue gas. To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimise the size and density of slurry droplets formed by the system. A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapour. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator before exiting the absorber which removes any entrained slurry droplets. The absorber effluent is sent to a reaction tank where the SO₂-alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once through systems dewater the spent slurry for disposal or use as a by-product.

Typical sorbent material is limestone, or lime. Limestone is very inexpensive but control efficiencies for limestone systems are limited to approximately 90%. Lime is easier to manage on-site and has control efficiencies up to 95% but is significantly more costly (Cooper 2002). Proprietary sorbents with reactivity-enhancing additives provide control efficiencies greater than 95% but are very costly. Electrical utilities store large volumes of limestone or lime on site and prepare the sorbent for injection, but this is generally not cost-effective for smaller industrial applications.

The volume ratio of reagent slurry to waste gas is referred to as the liquid to gas ratio (L/G). The L/G ratio determines the amount of reagent available for reaction with SO₂. Higher L/G ratios result in higher control efficiencies. Higher L/G also increases oxidation of the SO₂, which results in a decrease of the formation of scale in the absorber.

O&M costs are a direct function of reagent usage, so increasing the L/G increases annual costs. L/G ratios are approximately 1:1 for wet scrubbers and are expressed as gallons of slurry per 1000 ft³ of flue gas (liters of slurry/1000Nm³ of flue gas).

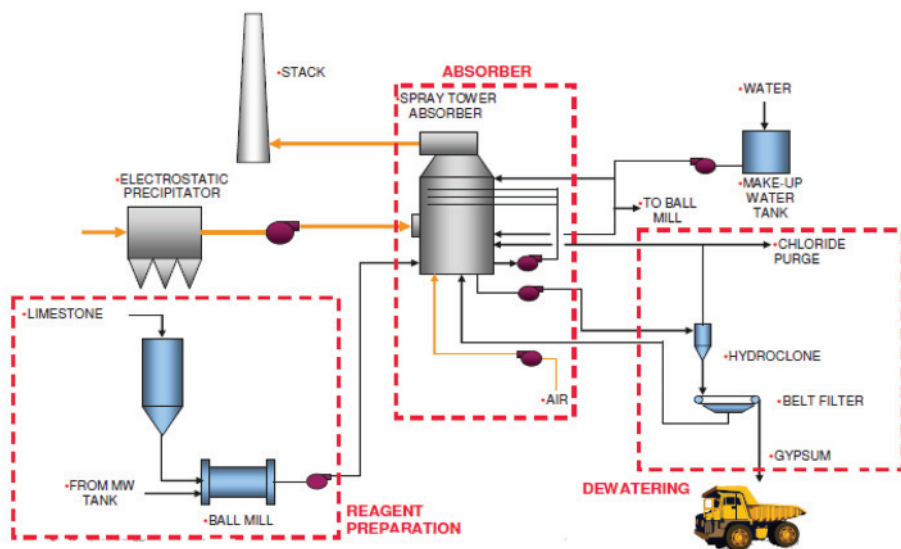


Fig.2: Limestone WFGD process diagram

Oxidation of the slurry sorbent causes gypsum (calcium sulfate) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing which reduces scale. In LSFO, air is added to the reaction tank which oxidizes the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycle slurry has a lower concentration of gypsum and scale formation in the absorber is significantly reduced. Gypsum can be commercially sold, eliminating the need for land filling of the waste product. In addition to scale control, the larger size gypsum crystals formed in LSFO settle and dewater

Semi-dry systems

Semi-dry systems, or spray dryers, inject aqueous sorbent slurry similar to a wet system, however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with SO_2 . The process forms a dry waste product which is collected with a standard particulate matter (PM) collection device such as a bag house or ESP. The waste product can be disposed, sold as a by-product or recycled to the slurry.

Various calcium and sodium based reagents can be utilized as sorbent. Spray dry scrubbers typically inject lime since it is more reactive than limestone and less expensive than sodium based reagents. The reagent slurry is injected through rotary atomizers or dual-fluid nozzles to create a finer droplet spray than wet scrubber systems.

The performance of a lime spray dry scrubber is more sensitive to operating conditions. A “close approach” to adiabatic saturation temperature is required to maximize the removal of SO_2 . However, excess moisture causes the wet solids to deposit on the absorber and downstream

equipment. The optimum temperature is 10°C to 15°C (20°F to 50°F) below saturation temperature. Lower L/G ratios, approximately 1:3, must be utilized to do the limitation on flue gas moisture. Flue gas with high SO_2 concentrations or temperatures reduces the performance of the scrubber.

SO_2 control efficiencies for spray dry scrubbers are slightly lower than wet systems, between 80% and 90% due to its lower reactivity and L/G ratios. Application of a single spray dry absorber is limited to combustion units less than 200 MW (2,000 MMBtu/hr) (IEA, 2001). Larger combustion units require multiple absorber systems. The

capital and operating cost for spray dry scrubbers are lower than for wet scrubbing because equipment for handling wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber since the flue gas is less humid. Typically applications include electric utility units burning low-to medium-sulfur coal, industrial boilers, and municipal waste incinerators that require 80% SO_2 control efficiency.

Sea water

Sea water FGD application is considered as a promising technology environmentally sound from engineering point of view and it is suitable for preferred of coastal power plants and for medium to high sulphur content. sea water use as a medium in the cooling system basically having a PH value of 7.6 to 8.4.

It is simple operation requiring no chemicals and low investment cost and low power consumption

Dry systems

Dry sorbent injection systems, pneumatically inject powdered sorbent directly into the furnace, the economizer, or downstream ductwork. The dry waste product is removed using particulate control equipment such as a bag house or electrostatic precipitator (ESP). The flue gas is generally

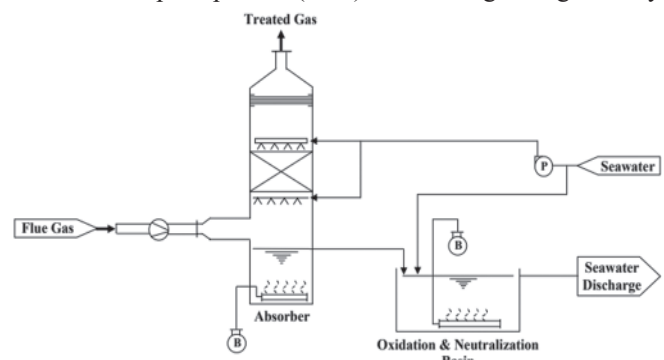


Fig.3. Simplified schematic diagram of seawater FGD system

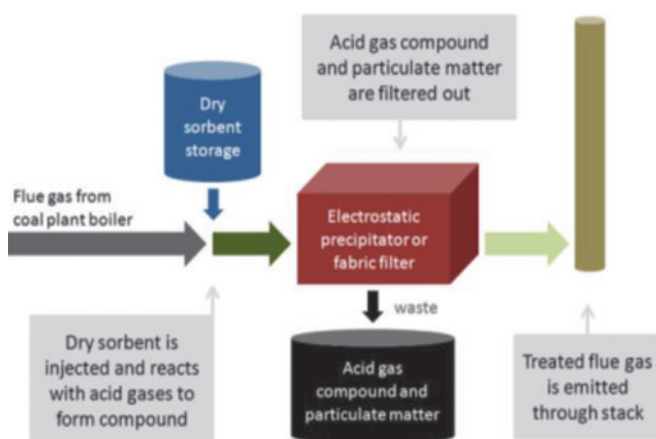


Fig.4: Simplified schematic diagram of dry system

cooled prior to entering the PM control device. Water can be injected upstream of the absorber to enhance SO₂ removal).

Furnace injection requires flue gas temperatures between 950°C to 1000°C (1740°F to 1830°F) in order to decompose the sorbent into porous solids with high surface area. Injection into the economizer requires temperatures of 500°C to 570°C (930°F to 1060°F). Duct injection requires the dispersion of a fine sorbent spray into the flue gas downstream of the air preheater. The injection must occur at flue gas temperatures between 150°C to 180°C (300°F to 350°F).

Dry sorbent systems typically use calcium and sodium based alkaline reagents. A number of proprietary reagents are also available. A typical injection system uses several injection lances protruding from the furnace or duct walls. Injection of water downstream of the sorbent injection increases SO₂ removal by the sorbent.

An even distribution of sorbent across the reactor and adequate residence time at the proper temperature is critical for high SO₂ removal rates. Flue gas must be kept 10°C to 15°C (20°F to 50°F) below saturation temperature to minimize deposits on the absorber and downstream equipment.

Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space, therefore, they are good candidates retrofit applications. SO₂ removal efficiencies are significantly lower than wet systems, between 50% and 60% for calcium based sorbents. Sodium based dry sorbent injection into the duct can achieve up to 80% control efficiencies. Dry sorbent injection is viewed as an emerging SO₂ control technology for medium to small industrial boiler applications. Newer applications of dry sorbent injection on small coal-fired industrial boilers have achieved greater than 90% SO₂ control efficiencies.

ADVANTAGES

- High SO₂ removal efficiencies, from 50% up to 98%
- Products of reaction may be reusable
- Difficulty of retrofit is moderate to low

- Inexpensive and readily available reagents

DISADVANTAGES

- High capital and O&M costs
- Scaling and deposit of wet solids on absorber and downstream equipment
- Wet systems generate a wet waste product and may result in a visible plume
- Cannot be used for waste gas SO₂ concentrations greater than 2,000 ppm
- Disposal of waste products significantly increases O&M costs

Cost estimates of FGD installation and operation in INDIA

The cost of FGD adoption may be divided into the capital cost of the FGD installation and annual operating costs. The capital costs of installation include one-time equipment purchase and the costs of setting up the FGD unit and connecting it to the boiler and flue stack. Based on the type of FGD, additional equipment, such as a limestone storage unit, mill and gypsum handling unit in the case of a wet limestone FGD, or water treatment in the case of a sea water FGD, also need to be purchased. Operating costs may be divided into fixed operating costs and variable costs. Fixed operating costs include periodic maintenance and labour to operate and maintain the FGD and accompanying equipment regardless of the degree of operation of the FGD. Variable costs include purchase of reagent (limestone in the case of wFGD) and by-product handling and disposal. Auxiliary consumption of electricity by the FGD is also part of the variable costs of operation.

FGDs have been in use in power plants in the United States since the 1970s to control SO₂ emissions. Studies based on operational data available for the US show that the installation and operating costs of FGD units vary substantially with the size of the plant (EPA 2009; Sargent and Lundy 2007). Further, costs of installation increase substantially when retrofitting the FGD unit to an old plant, as compared to the installation of an FGD in a new plant. This is due to the fact that for an existing power plant, equipment has to be moved to create space for an FGD. There are also costs associated with ductwork, wiring and modifications to the flue stack. Retrofitting an FGD incurs a cost, on average, that is 30 per cent above the cost of a newly installed FGD (Oskarsson et al. 1997; EPA 2007).

The sensitivity of the costs of FGD installation and operation to local labour and material market conditions implies that the transfer of cost estimates from the US to India is inappropriate. In the case of India, there are only few power plants where FGDs are currently operational – with the FGDs at Dahanu and Udipi having started operations fairly recently. With the limited experience of FGD operations in the Indian power sector, data on operating and installation costs is scarce.

To construct estimates of typical FGD costs in the Indian context, we rely on information from a variety of regulatory documents. Information obtained from tariff orders issued by the State Electricity Regulatory Commissions (SERC) in various States, for power plants that currently operate an FGD or from new projects that are planning to install one in the near future. we also use information from tariff determination norms and calculations of benchmark capital costs used by the Central Electricity Regulatory Commission (CERC). From this information we construct an estimate of the typical capital and operating costs of wet limestone and sea water FGDs in the Indian market. The assumptions regarding the individual cost parameters used to construct the cost estimates. we assume a capital cost of Rs.0.464 crore 78/MW for a sea water FGD (MERC 2009; and MERC 2011) and a cost of Rs.0.6 crore/MW for a wFGD79.

The greater costs for aAccording to limestone FGD reflect the expenditure on reagent handling and by-product disposal facilities. In comparison swFGD uses sea water which is discharged back into the sea thus not require as much capital investment. As a comparison, these figures are approximately \$100-150/kW, which is in the ball park of wFGD price in the US, prior to the recent spike in prices (Sargent and Lundy 2009).

The operating cost of a typical swFGD is obtained from the data for the Dahanu power plant in MERC (2009). Annual operating cost in 2009 was Rs.6.94 crores, which implies a cost of Rs.0.019/kWh. The operating costs for a wFGD are assumed to be 30 per cent higher than for a swFGD (the same ratio as the capital costs) because of the additional equipment and input handling requirements. The (net) variable operating costs for both swFGDs and wFGDs are assumed to be negligible. For a swf GD this is because of the absence of reagent purchase and disposal costs. For wFGD, the sale of the by-product, gypsum, often may offset most of the variable costs of FGD operation (Sargent and Lundy, 2009).80

To calculate total annual cost of an FGD, first, we calculate the levelized annual cost of capital. For a wFGD, this is derived from the capital cost in Rs./kWh assuming a 20 year facility life for retrofit units and a discount rate of 14 per cent. Next, the operating cost per unit of electricity produced (after adjusting for auxiliary power consumption) is added to the annualised capital cost to obtain the total annual cost of the FGD per unit of (net) electricity.

$$\text{Annual FGD cost (Rs.kWh)} = \frac{\delta * K}{1 - 1/(1 + \delta)^y} + \frac{[VC]}{1 - Aux}$$

Where,

K is the fixed capital cost of installation of the FGD in Rs./kWh,

VC is the variable cost per year expressed in Rs./kWh,

Aux is the per cent of electricity used by the FGD and its associated equipment,

δ is the discount factor, and y is the remaining life of the power plant.

The annual cost per unit of electricity is converted to a total cost per year using benchmark operation specifications 82 (as used by the CERC in tariff setting) instead of actual data on capacity utilization and generation. This is because operating characteristics, such as capacity utilization, may vary from year to year. In making investment decisions planners/firms will consider normative operations rather than short-term fluctuations. The estimated costs together with the reduction in mortality due to FGD installation is used to construct the cost per life saved for each power plant

Conclusions

There is a need in India to consider imposing SO₂ emissions standards on coal-fired power plants FGDs are the most prevalent method of SO₂ abatement in use across the world. It is thus important to assess the extent to which tighter SO₂ standard may be met by FGD installation. To inform this, we collect more data from cost-benefit analysis of FGD retro-fits at power plants across India. The results of my analysis show that FGDs represent a viable option to reduce SO₂ emissions in India. The estimated benefits from reduced premature mortality outweigh the costs of installation and operation at a significant number of coal-fired power plants. The extent to which FGDs pass the benefit-cost test depends crucially on the choice of the VSL. However, given the range of cost estimates, it is clear that there is significant scope for FGD adoption to deliver net benefits.

Further, it is important to consider that the estimated benefits may be regarded as a lower bound to the actual benefits from reduced SO₂ emissions. There are three reasons for this. First, the dispersion modelling used to link emissions to ambient concentration changes captures medium-range transport only. Not accounting for long-range impacts is likely to significantly underestimate the health damages from power plant emissions. Second, the health impacts are restricted to premature mortality in the population above 30 years. Thus impacts on morbidity and child mortality are not considered. And third, SO₂ emissions may also have an adverse impact on other sectors such as agriculture and forestry, which are not considered here. This analysis may be also be further refined as more data become available on FGD operations in India and more recent VSL estimates are developed for India.

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