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Benefit Cost Analysis of Emission Standards for Coal-based Thermal Power Plants in India

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July, 2018

Center for Study of Science, Technology and Policy (CSTEP) is a private, not-for-profit (Section 25) Research Corporation registered in 2005.

UrbanEmissions.info was founded with the vision to be a repository of information, research, and analysis related to air pollution.

Shakti Sustainable Energy Foundation works to strengthen the energy security of India by aiding the design and implementation of policies that support renewable energy, energy efficiency and sustainable transport solutions.

Designing and Editing by CSTEP

This report should be cited as: Srinivasan S., Roshna N., Guttikunda S., Kanudia A., Saif S., Asundi J.(2018). *Benefit Cost Analysis of Emission Standards for Coal-based Thermal Power Plants in India*, (CSTEP-Report-2018-06).

The CSTEP team conducted analyses on emissions, costs and health benefits. UrbanEmissions.Info conducted the dispersion modelling.

July, 2018

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Executive Summary

In December 2015, the Ministry of Environment, Forest and Climate Change (MoEFCC) notified emission standards for limiting Sulphur Oxides (SO_x), Nitrogen Oxides (NO_x), Particulate Matter (PM) and Mercury (Hg) emissions in coal-based Thermal Power Plants (TPPs). As of December 2017 (the deadline for meeting these standards), compliance was poor. Further, other government departments under the Ministry of Power (MoP) are mulling over a delay in implementation of these standards (Chaudhary, 2017; Mohan, 2017). In this context, this study evaluated the benefits and costs associated with the implementation of these emission standards.

Some of the key results of the analysis are presented below:

Without compliance, the study estimates that the SO_x and NO_x emissions will double, as compared to 2015 baseline emissions, while PM_{10} emissions will increase by 30% over the next 15 years. Implementing control technologies to meet norms could reduce the projected emissions of SO_x by 95%, NO_x by 87% and PM by 83%, in 2030.

To comply with the emission standards, power producers will have to make significant investments in installing Pollution Control Technologies (PCT), i.e., INR 0.5–1 crore (INR 5–10 million)/MW for nearly 80% of the plants in 2030. This study estimates an industry opportunity of around INR 2,50,000 crore (2500 billion) for the pollution control equipment industry, over the next 15 years.

Plants in five states will account for over 50% of the total costs needed for PCT installation, till 2030. Privately owned plants will face the highest costs for implementing these standards (over 45%), followed by state-owned (32%), and centrally-owned plants (24%). However, the lack of domestic manufacturing capacity, availability of technology providers in India, and the time taken for procurement and installation of PCTs may deter a time bound implementation plan.

Over 3.2 lakh premature loss of lives, 5.2 crore (52 million) Respiratory Hospital Admissions (RHA) and 126 million Work Loss Days (WLD) can be avoided till 2030, if the standards are met by 2025. Of the monetised health benefits (estimated to be INR 9,62,222 crore), 92% are from deaths avoided and 8% is from morbidity reduction i.e. avoided RHA and WLD.

The study highlights that the monetised benefits outweigh the costs within the initial years of PCT installation. The five states where plants need to invest more than 50% will also accrue the highest health benefits.

The electricity tariff is likely to increase between INR 0.25–0.75/kWh; this can have a substantial impact on the end consumers. The revision in electricity tariffs in order to meet the emission standards will be challenging to implement in many states, where power tariffs are regulated.

This study recommends a one year grant window to expedite the implementation of the norms to enable fund-raising for the high upfront costs. The government could set-up a grant of up to INR 93,500 crore (INR 935 billion), which power producers (of recent vintage) can avail over a one-year window. The remaining units can petition tariff revisions with electricity regulators, in keeping with the Electricity Act, 2003 and associated tariff guidelines.

Acknowledgements

The authors are thankful to the Shakti Sustainable Energy Foundation for providing us the support to conduct this study.

The authors acknowledge the following individuals for their timely contribution and reviews:

CSTEP colleagues for data collection and analytical inputs: Murali Ramakrishnan Ananthakumar, Venkatesh Vunnam, Arijit Chanda, Nikhilesh Dharmala, Pareexit Chauhan and Anuradha Venkatesh.

CSTEP Reviewers: S.S. Krishnan, Thirumalai N.C., Suresh N.S., Bellarmine K.C., Riya Rachel, Harshid Sridhar and Pratima Singh.

CSTEP Editorial support: Merlin Francis and Arushi Sen

Cover page design: Aswathy Shivaji

External Reviewers: V.T. Sathyanathan (Retd GM, BHEL), Anand Rao (IIT Bombay), Srinivas Murthy (former Chairman, KERC), Priyavrat Bhati (CSE), and Ashok Sreenivas (Prayas Energy Group).

Further, this project greatly benefitted from the emission standards related inputs from Dr. S.K. Paliwal, Scientist, Central Pollution Control Board (CPCB) and inputs on pollution control technology applicability from Piyush Banafer, Arun Unni, and Antony Mariasundaram (General Electric-Alstom).

Glossary

Emission standards	Emission standards are legal or regulatory requirements that quantify permissible limits of air pollutants that can be released by a specific source into the atmosphere.
Ambient concentration	It is an indicator of the state of the environment in terms of air quality, and is an indirect measure of population exposure to air pollution of health concern in urban areas.
Removal efficiency of a pollution control technology	Removal efficiency is the amount of pollutant captured/removed by the pollution control equipment. It is represented in terms of percentage of quantity of inlet pollutant.
Plant load factor	Plant load factor is the measure of capacity utilisation of plant. It is measured in terms of output of a power plant with respect to the maximum output it could produce.
Gross calorific value	Heat produced by combustion of unit quantity of a solid or liquid fuel when burned is termed as calorific value of a fuel.
Coal blending	Coal blending is a process of mixing coals of various calorific value and composition to improve the calorific value of coal per unit quantity.
Flue gas stack	The flue gas stack is a type of chimney through which combustion gas from power plants were given out to atmosphere. The height of flue-stack ranges between 150 m and 275 m for Indian coal thermal power plants. The height and volume of flue gases affect the flue gas dispersion.
Eulerian photochemical atmospheric dispersion model	Eulerian model is a numerical technique used to simulate air pollutant dispersion. In Eulerian models, the region of interest is divided into horizontal and vertical cells and equations of continuity are solved in each cell (Zannetti, 1993).
Horizontal resolution of grid	The smallest cell dimension for dispersion modelling at 0.25 degrees.
Emission trajectories	The progression of emissions from TPP units over a period of time. In this analysis annual emission loads were estimated for a 15 year time period of 2015-2030.These estimations are dependent on what controls are applied and when to meet the standard.
Baseline emission	Baseline emissions are underlying characteristic (in concentration or emission factor terms) of different gases in the flue of TPPs with existing levels of controls as on 2015.
Partial equilibrium	It is the condition of economic equilibrium which takes into consideration only a part of the market, ceteris paribus, to attain equilibrium. This makes analysis simpler than in a general equilibrium model which includes an entire economy. Under a dynamic condition in energy models, illustratively, prices adjust until supply equals demand.

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1. Introduction

1.1 Trends in Coal-based Power Generation and Emissions

Coal has dominated the power supply mix since the mid-1980s (Figure 1). As of 2017, coal-based Thermal Power Plants (TPPs) accounted for 77% of the total electricity generation. Around 58% of India's total installed capacity, of 334 GW, was coal-based TPPs (CEA, 2017 b). Given coal's dominance in power generation, the electricity sector has been a major source of pollutant emission.

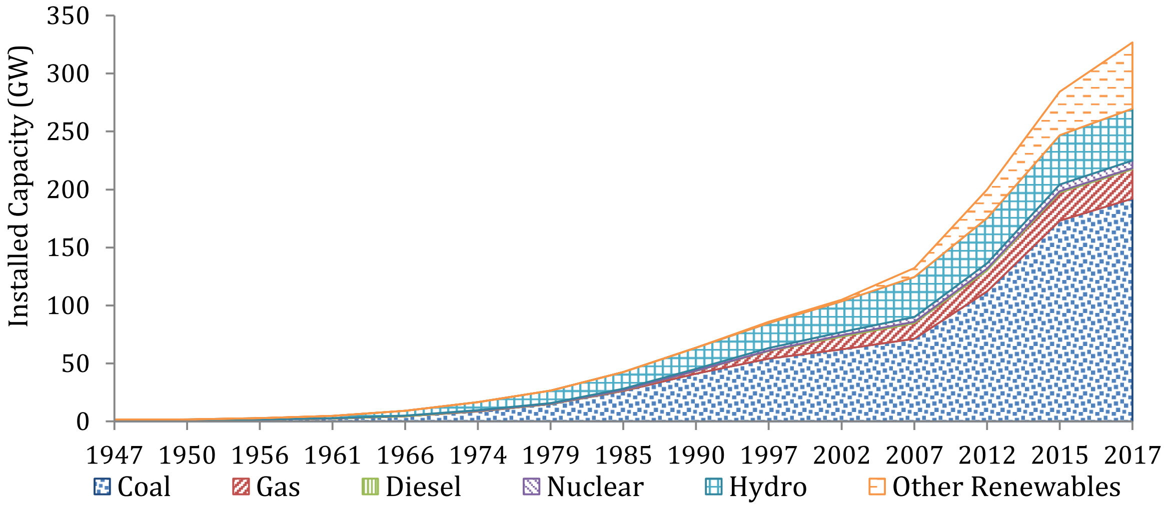

Figure 1: Post-Independence Growth of Power Sector in terms of Installed Capacity (MW)

Source: (CEA, 2017 b)

In 2015, the power sector contributed 50% of the 10,500 kT of annual Sulphur Oxide (SO_x) emissions, 30% of the 7,332 kT Nitrogen Oxide (NO_x) emissions, and 8% of the 6,331 kT of Particulate Matter of size ≤2.5μm ($PM_{2.5}$) emissions (IEA and IIASA, 2015). The coal TPPs were estimated to be the highest contributor of SO_x and NO_x emissions. These local pollutants lead to acute and chronic respiratory diseases, leading to premature deaths (HEI, 2010).

Despite the government's plans for increasing renewable energy generation, thermal power is likely to dominate generation in the foreseeable future. Coal is likely to contribute up to 80% of the electrical generation required in 2022, and over 60% of electrical generation in 2030 (Byravan, et al., 2017) (CEA, 2016 b). As per the Central Electricity Authority's (CEA) plans, around 50 GW of new coal power generation units are under construction (CEA, 2016 b). Further, CEA has estimated that an additional coal-based capacity of 44 GW will be required during 2022–27, to meet demand.

This implies increased pollution loads of SO_x, NO_x and PM from the power sector. Earlier, the Ministry of Environment and Forests had published norms for flue gas stack height to facilitate wider dispersion of pollutants[1]. Over time, emission standards were also prescribed for particulate matter. With substantial increase in coal-based generation in the last decade, and

[1] Dispersing pollutants can minimise the hazardous effects of pollutants by aiding it to spread over a large area, thus minimising its concentration in nearby areas. Stack height requirements: Unit capacity <210 MW = 14 (Q) $^{0.3}$. Where, Q is emission rate of SO_2 (kg/hr). Between 210 and 500 MW = 220 metres; >=500 MW =275 metres.

the increase in SO_x and NO_x emissions, MoEFCC announced new pollutant emission standards, in December 2015, to limit emissions from coal and lignite TPPs (MoEFCC, 2015).

1.2 Adequacy of Environmental Protection Amendment Rules, 2015

The standards notified in December 2015, mandated a limit on SO_x, NO_x, and Hg (mercury) concentration in the flue gas leaving the stack, and tightened the old norms (1989) for PM emission concentrations. The norms were differentiated by plant unit, capacity and vintage (Table 1 and Table 2).

Table 1: New Emission Standards

Installation Period	Unit Capacity (MW)	Pollutants concentration (mg/Nm³)			
		SO_x	NO_x	PM	Hg
Before 2003	<500	600	600	100	0.03
	≥500	200			
2003–2016	<500	600	300	50	0.03
	≥500	200			
From 2017	All Units	100	100	30	0.03

Table 2: Old Emission Standards

Unit Capacity (MW)	Pollutants concentration (mg/Nm³)			
	SO_x	NO_x	PM	Hg
<210	None	None	350	None
≥210	None	None	150	None

Source: (MoEFCC, 2017); (Implementation of Pollution Control– II, CPCB, 2008)

The new standards are comparable to the stringent norms set in the United States of America (USA), European Union (EU) and China (WRI, 2012) . Yet, there is concern over the lack of specification of a minimum time period for measurement[2]. The US and EU specify a 30-day rolling average, which enables compliance checks (Sahu, 2015). Also, measurement of pollutants, in terms of concentration, depends on the excess air fed into the boiler; standards can be met by diluting the flue gas, i.e., feeding-in more excess air into the boiler. An amendment to the Environment Protection Amendment Rules (EPAR) in 2017, addressed some ambiguity on excess air contribution to pollutant concentration by specifying the composition of oxygen (6% on dry basis) in flue gas (MoEFCC, 2017).

Moreover, in the absence of a comprehensive industry document to guide the TPP industry or regulators, there are three uncertainties that merit attention while thinking about this air pollution regulation and its efficacy: (1) baseline emission profile; (2) pollution control options; and (3) benefits to society.

Baseline Emissions in Indian TPPs

In Indian TPPs, there is large uncertainty on the actual baseline emission concentrations. Although the Continuous Emission Monitoring Systems (CEMS) are mandated by MoEFCC in

[2] Excess air of 10-30% is usually fed into the boiler to ensure complete combustion of coal.

TPPs, data has not been made public yet (CPCB, 2017). Further, to derive these values, coal composition and unit level performance characteristics are required. While the CEA reports some of the performance related metrics, such as Plant Load Factors (PLF) and historic generation, only few plants record or report the chemical coal composition or Gross Calorific Value (GCV) of the coal used.

Data collected during the course of this study indicated that Indian TPPs use a combination of sub-bituminous coal and lignite—the coal sourced can be mapped to nine geographically distinct coal fields in India and abroad (South African, Indonesian and Australian coal) (Details in Annexure-A) The calorific value of coal from domestic collieries is low, while imported coal has higher calorific value. Blended domestic and imported coal has been used in the past to address non-availability of domestic coal. Several new plants have listed imported coal as their primary fuel source, in environmental impact assessment documents. Imported coal is relatively higher in sulphur content (>0.5%), implying increased SO_x emissions. Meanwhile, a plant relying on domestic coal results in higher PM emissions due to its higher ash content (30–40%).

MoEFCC reported current average emission factors of pollutants as 7.3 g/kWh for SO_x, 4.8 g/kWh for NO_x, and 0.98 g/kWh for PM_{10} (PIB, 2015). Several other studies also reported emission factors estimated based on different assumptions on a representative coal composition, or power plant operating characteristics (Garg, Kapshe, Shukla, & Ghosh, 2002; Chakraborty, et al., 2008; Mittal, Sharma, & Singh, 2014). Moreover, at the system scale, research has indicated that pollution impacts were not isolated to the individual plant's site, and emissions dispersed over 200 km away from the plant site (Guttikunda & Jawahar, 2014). However, disaggregated and system level impacts have not been evaluated.

Pollution Control Options

Emission of NO_x, SO_x and PM can be reduced by installing Pollution Control Technologies (PCTs) at different stages of a power plant's operations; pre-combustion, in-combustion, and post-combustion. We compiled a list of technologies applicable in the Indian context, along with their costs from literature (Bhati & Ramanathan, 2016; GE Power, 2016). However, technology providers in India are limited, and data on cost typically represent the global market. The detailed review of these technologies showed that the cost of implementation, especially upfront costs, are the highest for post-combustion options, while pre-combustion technologies are the least costly (Refer Annexure C).

The pre-combustion control technologies that can be adopted in coal TPPs are coal washing and blending. Installation of Low NO_x Burner (LNB) and Over-Fire Air (OFA) inside the boiler are the in-combustion controls available for NO_x. Limestone injection into the furnace is an effective in-combustion control applicable for SO_x reduction. The available post-combustion control technologies are Flue Gas Desulphuriser (FGD) for SO_x, Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR) for NO_x, and Electrostatic Precipitators (ESPs) or fabric filters for PM. The percentage of emission reduction for PCTs varies between 25% for SO_x with coal washing, and 99.6% for PM reduction with high efficiency ESP. Most of the existing TPPs have an ESP installed to meet the earlier emission standards. Lastly, although standards are also specified for Hg, the current emission level of Hg from coal TPPs is lower than the standard's specification (estimated at average of 0.012 mg/Nm^3 in Annexure-B). Hence, additional PCT installations will not be required for Hg control.

This study has consolidated recent data and evaluated costs in the context of industry-wide adherence to the new standards. This is useful since speculation on costs have deterred power producers. They have sought delays in the deadline to meet new standards, and require clarity on tariff revisions that will relieve financial stress. MoP, in consonance with the industry, announced a phasing plan, moving the original MoEFCC deadline from 2019 to 2023 for different plants (CEA, 2017 a). The MoEFCC also indicated its support to MoP in the Supreme Court, to extend the compliance deadline to 2022, recently (Mohan, 2017).

Benefits of Meeting New Standards

Compliance with the new standards will reduce local pollution, and yield health and ecosystem benefits[3]. Only a select few studies have evaluated the health benefits from installing pollution controls in individual plants—the industry-wide implication has not been evaluated, yet. In the plant level analyses, costs of controls have been compared with the health benefit; for example, avoiding one premature death is estimated to cost INR 0.15 crore (INR 1.5 million) to INR 3 crore (INR 3 million), depending on the exposed population and plant capacity (Malik, 2013). Other studies have demonstrated that (depending on a range of monetary values assigned to health benefits) interventions to install pollution controls in Indian TPPs pass the benefit vs. cost test (HEI, 2010; Pope, Cropper, Coggins, & Cohen, 2015; Gunatilake, Herath; Ganesan, Karthik; Bacani, Eleanor, 2014).

In this context, we felt that it is relevant and timely to assess the social benefits and costs of implementing the emission standards, across the industry. We felt that this could aid in convincing stakeholders on the usefulness of the new emission standards, thus facilitating installation of PCTs in a time-bound manner.

2. Study Objective

This study aims to evaluate the implications of new emission standards by carrying out a system-wide benefit-cost analysis for the period 2015 to 2030. We chose this time frame for evaluating costs and benefits since power sector plans were available till 2030 in the public domain (including the National Electricity Plan scenarios to incorporate the 40% fossil-free power generation capacity target as per India's Nationally Determined Contributions). The following components have been included in the study:

1) Evaluation of implications of adherence to new emission standards, by:
   a. Assessing the applicability of control measures and associated technology costs
   b. Estimating the impact on cost of power generation and total system costs
   c. Assessing and monetising the social and health benefits

2) Recommendations to facilitate implementation, by:
   a. Identifying challenges in compliance

[3] Studies have shown that reduced SO_x can reduce soil and rain acidification thereby reducing threat to biodiversity and ecosystem services. However, assessment of these social benefits was not included in this study.

b. Presenting the '*true cost of coal*', accounting for environmental externalities and assessing regulatory requirements

3. Methodology and Approach

In order to evaluate the benefits and costs of implementation of the emission standards, this study pursued three tracks of analysis: (1) Interpreting the emission standards in terms of normalised mass flow rates; (2) Estimating emission loads from TPPs (under different levels of compliance, at a system level); and (3) Quantifying social costs and benefits (including technology investment, running costs, health costs or benefits, and associated tariff implications). The pictorial representation of the approach is shown in Figure 2.

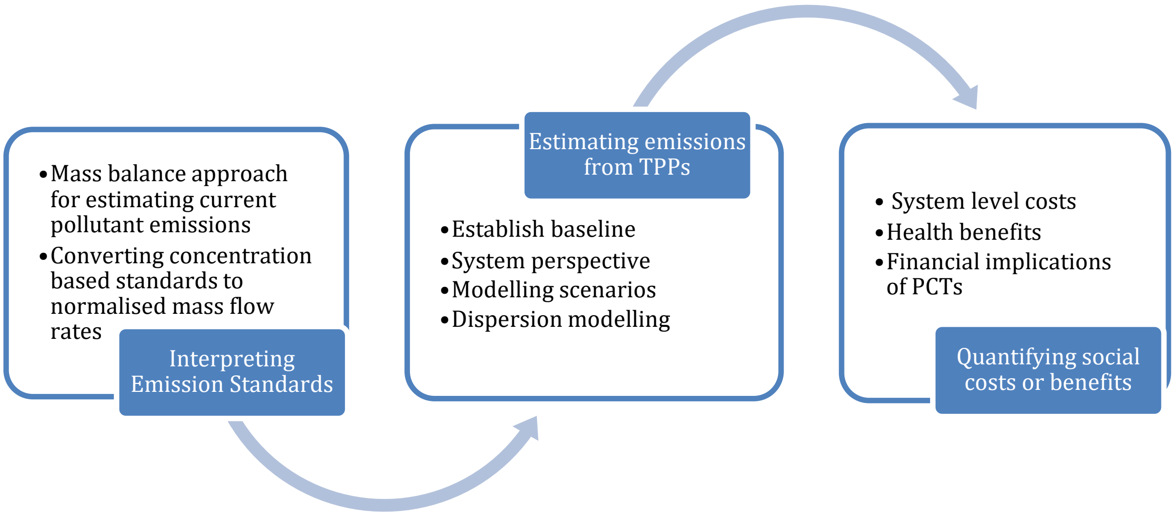

Figure 2: Pictorial Representation of the Approach

3.1 Interpreting Emission Standards

The standards for various pollutants have been specified in concentration terms. However, in order to understand the impact of the standards on different capacity and vintage, or in other words, different pollution loads, the standards needed to be converted to mass flow rate terms.

As mentioned in the Introduction section, data on the baseline emissions (concentrations) for various TPPs are not available in the public domain. The diversity in coal linkages, i.e., the GCV of domestic, imported and blended coal, and their respective elemental composition, needs to be factored into any estimation of current emission mass flow rates. Hence, a stoichiometric mass balance analysis was carried out using data available in peer-reviewed literature, government reports, and technical reports to estimate current emission flow rates and factors. These were normalised with respect to input energy, and compared to the requirements under the emission standards.

This section provides the methodology used to estimate current pollutant emission factors from TPPs. It also provides the steps followed to convert concentration based emission standards into normalised mass metrics.

Estimation of Current Pollution Emissions

Equation 1 shows the mass balance approach for normalised mass flow for emissions in TPPs.

Equation 1

$$\frac{mg_i}{MJ_{Cj}} = f\left[\{kg_{Cj}\}\{\%\ of\ k_{Cj}\}\{a_k\}\right]$$

Where, $\frac{mg_i}{MJ_{Cj}}$ is the normalised emission factor for pollutant *i* for coal type$e$;

kg_{Cj} is the quantity of coal C_j equivalent to 1 MJ of input energy;

$\%\ of\ k_{Cj}$ denotes percentage composition of chemical constituent k in the coal type C_j;

a_k is the combustion conversion factor of k at given boiler condition.

The input data for this equation was obtained from an in-depth literature review and feedback from experts. The approach used for data collection is presented below:

Step 1: Identify the types and classifications of coal used in Indian TPPs (MoC, 2016).

Step 2: Gather data on coal composition and calorific value (Chandra & Chandra, 2004; CERC, 2014; Falcon & Ham, 1988; Belkin & Tewalt, 2007).

Step 3: Identify conversion rates of chemical components during combustion based on experimental studies (Cai, Guell, Dugwell, & Kandiyoti, 1993; Brimblecombe, 1996; Mittal, Sharma, & Singh, 2014; Pershing & Wendt, 1977; Bartonova, Juchelkova, Kilka, & Cech, 2011; USEPA, 1998).

Step 4: Identify technical operating parameters for the boiler, existing pollution control equipment and stack exit physical characteristics (Chandra & Chandra, 2004; Mittal, Sharma, & Singh, 2014; Chakraborty, et al., 2008; Khan & Khan, 2014).

Based on the review of literature, we identified nine domestic collieries supplying coal to TPPs: Eastern Coalfields Limited (ECL), Northern Coalfield Limited (NCL), Central Coalfields Limited (CCL), South Eastern Coalfields Limited (SECL), Mahanadi Coalfields Limited (MCL), Singareni Collieries Coal Limited (SCCL), Bharat Coking Coal Limited (BCCL) and Lignite[4] (same composition was considered for all lignite collieries as data in literature was available only for Neyveli Lignite). Three imported coal types, mainly used in Indian TPPs, are Indonesian, South African and Australian. The calorific value of domestic coal categories varies between 3800 and 4500 kcal/kg, while the value for imported coal is between 6300 and 7800 kcal/kg. The ash and sulphur content, from literature for the 12 coal classifications used in this study, is given in Figure 3.

[4] Includes Kutch lignite and Neyveli lignite

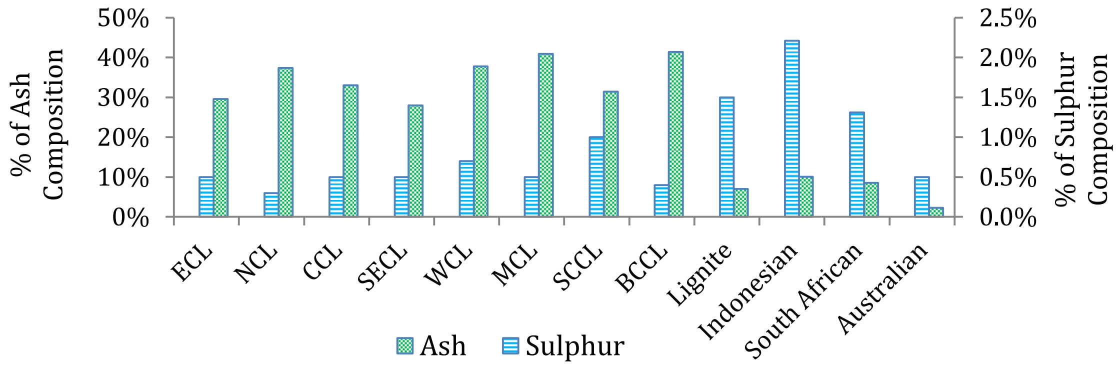

Figure 3: Ash and Sulphur Content (%) in Various Coal Types

Domestic coal types are seen to have a low share of sulphur (≤0.5%) and higher ash content (30–40%) as compared to imported coal. This implies higher PM emission factors and lower SO_x emission factors for TPPs that consume domestic coal. Meanwhile, imported coal from Indonesia and South Africa have higher sulphur (>2%) content than domestic coal, thus has higher SO_x emission factors. The details of coal composition and GCV of these coal types are presented in Annexure–B.

The flow rate of NO_x, SO_x and PM_{10}[5] were estimated using stoichiometric equations, assuming an overall plant efficiency[6] of 33% for a typical Indian TPP (CEA, 2013). The key operational parameters and conversion factors for various chemical constituents are given below.

Key Assumptions

- Combustion temperature in boiler is 1500 K (Cai, Guell, Dugwell, & Kandiyoti, 1993)
- Excess air supplied to boiler is 20% (Mittal, Sharma, & Singh, 2014)
- 92.5% of sulphur in coal is combusted and only SO_2 is formed (Mittal, Sharma, & Singh, 2014)
- 20% fuel nitrogen is converted to NO constituting 72.5% of the total NO_X formed (Pershing & Wendt, 1977)
- PM_{10} emission was calculated as follows: 2.3 times the % of ash in 1 lb of coal (USEPA, 1998)
- Temperature and pressure at flue gas stack is taken as 422 K , 1atm (Chakraborty, et al., 2008)

Baseline emission concentration varies based on the coal linkage. SO_x concentration in flue gas is the least for NCL (1053 mg/Nm³) and as high as 3152 mg/Nm³ for SCCL, within the Indian sub-bituminous categories; it is the highest for Lignite (7362 mg/Nm³). In comparison, the SO_x concentration for Indonesian coal is higher at 4819 mg/Nm³. The NOx concentrations for Indian and imported coal are in a similar range as the percentage shares of nitrogen in the fuel are similar. The average NO_x concentration for different coal types was estimated as 952 mg/Nm³. The average PM_{10} concentration in flue gas, accounting for ESP of removal efficiency 97% (to cater to older norms), is 183 mg/Nm³ for domestic coal, and 24 mg/Nm³ for imported

[5] It is assumed that SO_x formed during combustion is in SO_2 form. Similarly, for NO_x, only NO is considered.
[6] Overall plant efficiency depends on boiler efficiency and steam cycle efficiency (Reddy, 2014).

coal. Details of this calculation, emission factors in terms of mg/MJ_{coal} and sensitivity with plant operational parameters are provided in Annexure-B.

Conversion of Emission Standards: Concentration to Mass Flow Terms

Mass flow rate estimation is a more robust approach, eliminates dependencies on excess air, and allows for a diverse representation of coal linkages. The emission standards in concentration terms were converted into mg/MJ_{coal} using average F-factor (Flue Gas Volume/ Thermal Energy Input) derived for different coal types (Equation 2). Details are provided in Annexure-B.

Equation 2

$$MoEFCC\left(\frac{mg}{Nm^3}\right) * F\text{-}factor\left(\frac{Nm^3}{MJ}\right) = Emission\ standard\ \left(\frac{mg}{MJ_{coal}}\right)$$

3.2 Estimating System Wide Emission Loads from Coal TPPs

The pictorial representation of the methodology for estimating system wide emission loads is shown in Figure 4.

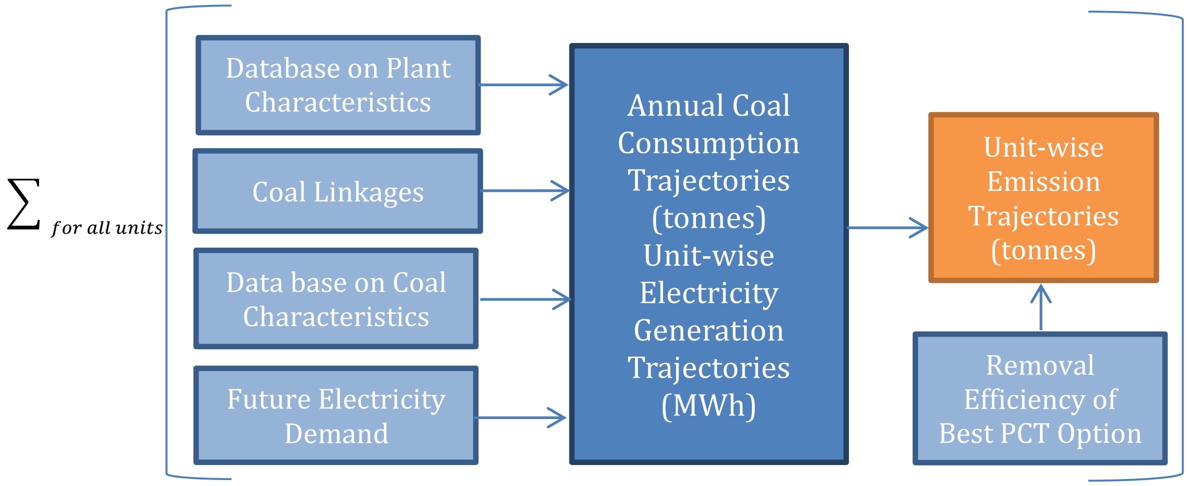

Figure 4: Schematic for Estimating System Level Emissions for a given Unit

The emission trajectories for all TPP units operating between 2015 and 2030 were estimated using derived emission factors from the mass balance analysis. Additional input data required for emission load calculation are plant level coal linkages, existing PCT, and power plant characteristics such as historic plant efficiency and PLF. This data for each TPP unit was collected from two databases and validated with environmental clearances (CoalSwarm, 2016; CEA, 2015). The percentage share of installed capacity linked to various coal types is shown in Figure 5[7]. Wherever data on coal was not available (~20 GW), the nearest coal field or port was considered. In 2015, as per our estimation, the highest consumption was for SECL and MCL coal (among domestic categories) and Indonesian coal consumption was the highest in

[7] Several plants in India consume two or more coal types. For the current study, single coal type is considered to reduce complexity. Among plants that consume two or more domestic coals, the cheaper option was considered for the analysis. Amongst those which use imported with domestic coal, 100% imported coal was considered.

the imported coal category. The share of Indonesian coal will increase to 11% by 2030, driving up the overall SO_x emission loads.

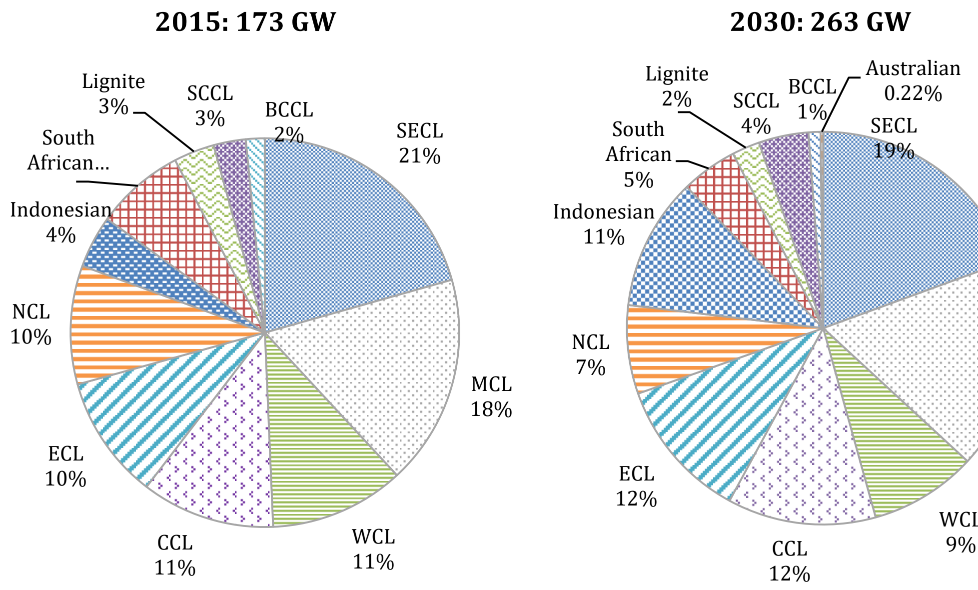

Figure 5: Coal Linkages of TPPs in 2015 and 2030

Figure 6 shows the district-wise installed capacity of coal TPPs in 2015 and 2030. As shown, more coal TPPs will be operational in coastal regions, and states such as Chhattisgarh, West Bengal and Jharkhand, in 2030.

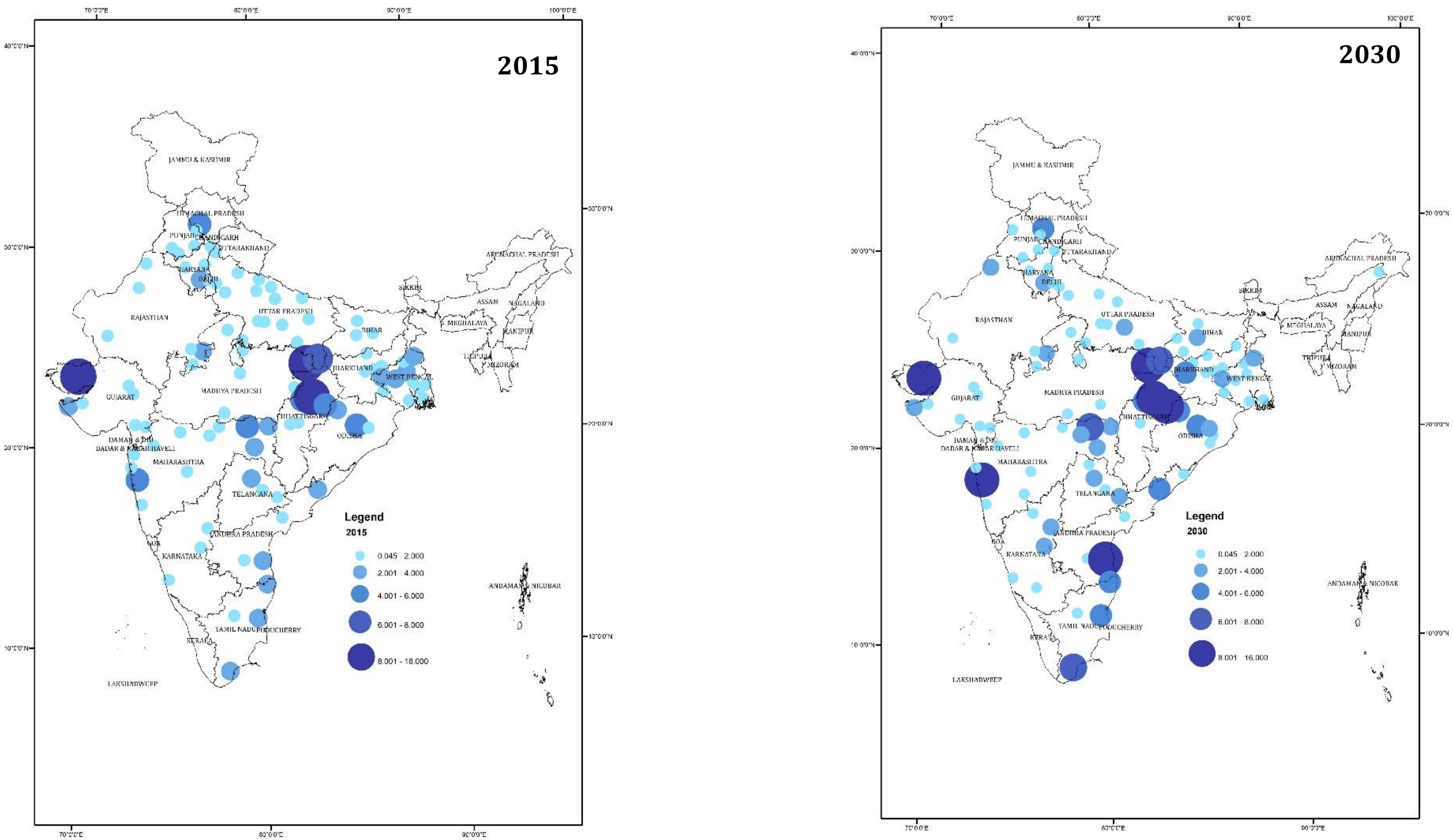

Figure 6: District-wise Installed Capacity as on 2015 and 2030[8]

[8] The size of bubble denotes the installed capacity. The smallest circle and largest circle represents ≤500 MW and 4620 MW respectively.

Estimating Unit-wise Power Generation Trajectories

CSTEP's India Multi Region TIMES model (IMRT) was used to arrive at power generation profiles for TPPs in India during 2015–30. TIMES (The Integrated MARKAL EFOM System) is a dynamic partial equilibrium optimisation model, which is widely used for energy and environment systems analysis to explore least cost and low emission pathways. It supports technology level representation of primary energy (coal, gas, oil, etc.), transformation (electricity generation, refineries) and end-use (industry, buildings, transport) sectors. The power sector has been modelled at the unit level, with states as regions. An electricity-only version of the model was used for this study, which is driven by exogenous electricity demand, specified at the state level. Per capita electricity consumption was projected[9] at the national level to derive national level electricity demand, based on projected population (United Nations, 2017) . This demand was then allocated to states based on projected shares of states. CSTEP's consolidated power plant database included existing units (as on 2015) and planned units (expansion and new proposed). In new subcritical, supercritical and ultra-super critical plants, efficiencies of 36%, 38% and 41% were assumed respectively. A summary of the database used is provided in Table 3. Plants operating during 2015–30 were seen to operate at a weighted average PLF of 74% in 2030[10]. Additional plants beyond the CEA's plan were not required to meet the exogenous electricity demand. Costs of solar PV technologies reflect the current reverse bidding tariffs of INR 4/kWh. All other model inputs on technology costs are consistent with previous national modelling exercises conducted by CSTEP [Refer supplementary material of (Byravan, et al., 2017)].

Table 3: Summary of Power Plant Database and Installed Capacity (GW) in 2030

Commissioning year	Category	No of Units	Total Capacity GW	%	Ownership					
					Centre		State		Pvt	
					No of Units	Capacity GW	No of Units	Capacity GW	No of Units	Capacity GW
Before 2003	Plant Capacity <500 MW	346	46	18 %	81	12	234	31	31	3
	Plant Capacity ≥500 MW	24	12	5%	18	9	5	3	1	1
Between 2003 and 2016	Plant Capacity <500 MW	163	37	14 %	16	4	50	12	97	21
	Plant Capacity ≥500 MW	136	93	35 %	45	25	28	21	63	47
On or after 2016	Plant Capacity <500 MW	37	7	3%	3	1	6	2	28	5
	Plant Capacity ≥500 MW	115	68	26 %	20	10	28	19	67	39
	Total	821	263		183	61	351	86	287	116

[9] Per capita electricity consumption will reach around 2400 kWh/capita by 2030.
[10] PLF Range: 66% in older plants and around 90% in newly installed plants that require lesser shutdown periods for maintenance works.

Further details on model inputs are provided in Annexure A. Based on these, the IMRT model was used to generate a reference trajectory of state-wise generation profiles. This was mapped to individual power plants to derive coal consumption and emissions at flue-stack.

PCT Module and Scenario Phasing

The PCT module laid out the levels of controls based on the choice of control technology under difference scenarios. Pollution control measures can be enforced in different stages of power plant process, targeting one or more pollutants. A typical power plant can be disaggregated into three stages depending on the layout — pre-combustion, in-combustion and post-combustion [Refer Figure 7].

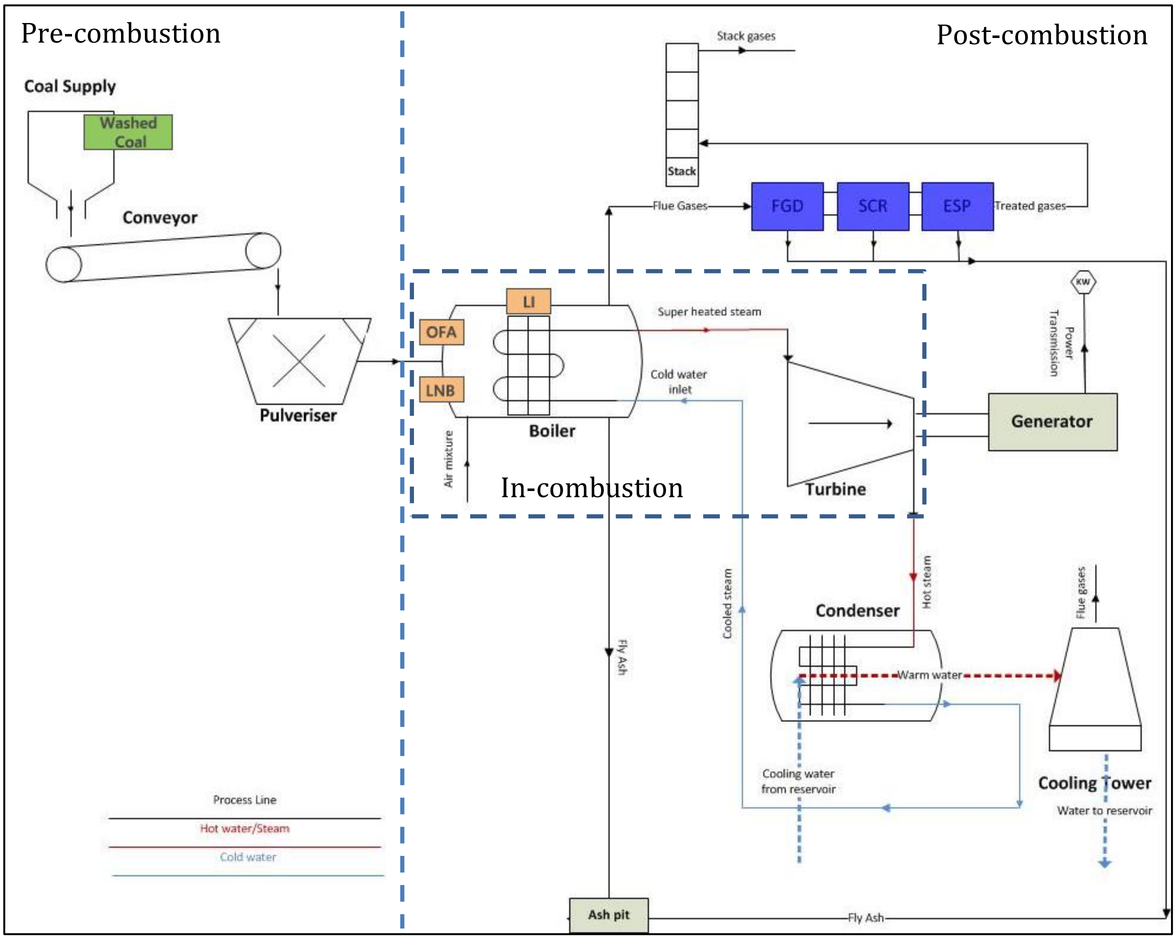

Figure 7: Schematic Diagram of Coal TPPs with PCTs

Data on PCTs (technical and cost parameters) was gathered after extensive literature survey and discussions with technology manufacturers and providers. Detailed data are provided in Annexure C. Table 4 illustrates, qualitatively, the trade-offs between removal efficiency and cost for various PCTs (Bhati & Ramanathan, Clearing the Air, 2016) (Cropper, Gamkhar, Malik, Limonov, & Partridge, 2012).

Table 4: Cost vs Removal Efficiency of Pollution Control Technologies

Removal η / Cost	**Low**	**Medium**	**High**
High			FGD (90- 98% SO_2) (85-95% Hg), Selective Catalytic Reduction (SCR)(95% NO_x)
Medium	Over-fire Air (OFA) (20-45% NO_x) Low-NO_X Burner (LNB) (30-45% NO_x)	Dry Sorbent Injection (35-60% SO_2) Selective Non-Catalytic Reduction (SNCR) (40-75% NO_x) Dry Sorbent Injection + Coal Beneficiation (68.5% SO_2) LNB +OFA (52.5%)	High-performance Electro-Static Precipitators (HESPs) (99.4-99.9% PM), Bag Filters (99.6-99.9% PM)
Low	Coal Beneficiation (25% SO_2), (30% PM)		

Pre-Combustion In-Combustion Post-Combustion

The usage of washed coal instead of raw coal can reduce SO_x emissions in flue gas by 25% and PM emissions by 30% (Cropper, Gamkhar, Malik, Limonov, & Partridge, 2012). Washed coal can also improve the plant's performance by enhancing overall plant efficiency by 1.2%, and increasing plant load factor (PLF) by 4% (Zamuda & Sharpe, 2007).). It can also improve the ESP efficiency to design efficiency, ruling out the need for upgrading older ESPs to meet new standards (Zamuda & Sharpe, 2007). NO_x reduction technologies such as OFA and LNB can be considered for units facing less stringent norms. Further, limestone injection with 55–60% SO_x removal efficiency can be considered as an alternative to the land intensive FGD installations (~1.5 acres for 210 MW) in existing plants that are facing land availability constraints. In new units, facing more stringent standards, post-combustion control technologies such as FGD for SO_x, SCR or SNCR for NO_x, and high performance ESPs/Bag filters for PM reduction will likely be required. However these can increase the land footprint required. The reduction of PM_{10} with controls also leads to a reduction in $PM_{2.5}$ loads from the flue stack (van Harmelen, Visschedijk, & Kok, 2002). Moreover, most post combustion technologies require the TPP to be shut down during installation of the PCTs. This ranges from two to four weeks for a wet FGD to six months for a dry FGD (which requires modification in the existing PM filters). For PM_{10} control upgrades and in-combustion NOx technologies, installation time required is less than six months. However procurement and installation of post combustion technologies can take up to two years (Bhati & Ramanathan, 2016).

We developed a PCT applicability matrix for each plant. This was determined by emission reduction required, derived from base emissions (determined by coal linkage and plant operating characteristics), and the emission standard (based on vintage and unit capacity), as well as natural resource linkage (fresh water/land availability). The final choice of technology was determined by costs. This included upfront and running costs (including costs from increase in auxiliary consumption, and reduction in power plant efficiency). Refer Figure 8 for logic flow.

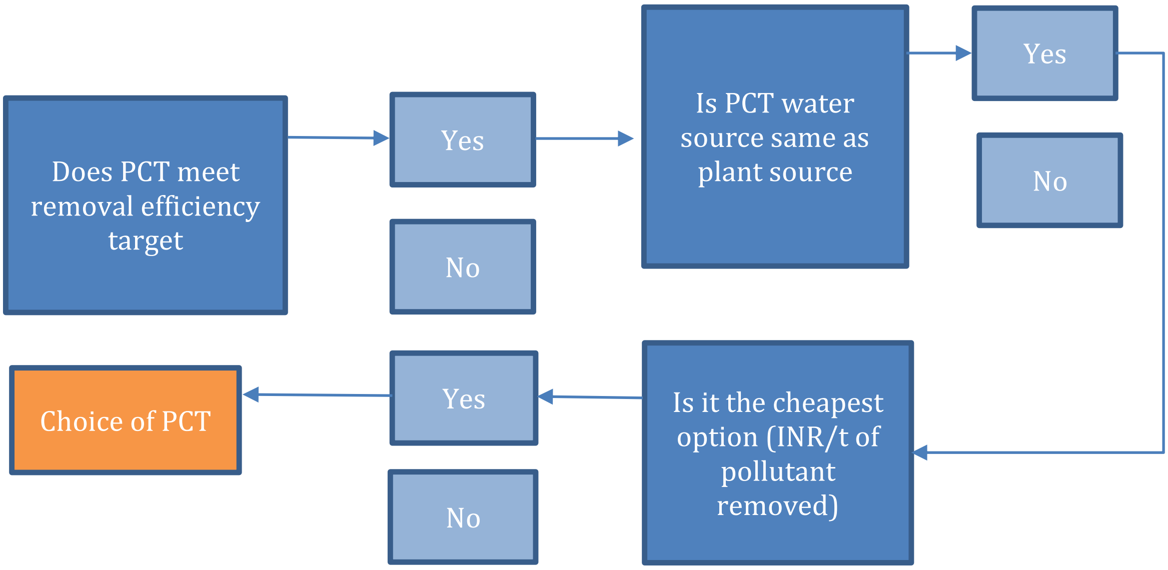

Figure 8: Logic Flow for PCT Choice

In certain cases, a combination of pre-combustion and in-combustion technologies can also be used to meet the desired emission standards and lower costs. However, very few plants can use this to meet their emission standards, and others will have to invest in high capital cost options.

Table 5 highlights that plants of vintage 2003–16 need to invest in high cost PCTs to meet emission standards for NO_x and SO_x, yet upgradation of existing ESPs will not be costly for them. However, several new plants (up to 20 GW which use high ash content coal) may need to use washed coal along with planned ESP installations to achieve the prescribed emission norm.

Table 5: Qualitative Representation of TPP Installed Capacity and PCT Investment

Pollutant	**SO_x**		**NO_x**		**PM_{10}**	
Commissioning Year	High cost PCTs (GW)	Medium cost PCTs (GW)	High cost PCTs (GW)	Low cost PCTs (GW)	High cost PCTs (GW)	Medium Cost PCTs (GW)
Before 2003	47	11	8	50	0	58
Between 2003-16	121	9	127	3	0	130
After 2016	75		75	0	16	59

Scenarios for Phasing of Emission Standards

This study explored three scenarios; a reference scenario and two policy scenarios to analyse the impact of phased PCT installation on system level costs and benefits.

Reference Scenario: For the reference case, ESPs of removal efficiency ranging 95–98.5% was considered, since older TPPs are assumed to adhere to previous emission standards for PM (Table 6).

Table 6: ESP Removal Efficiency Specification based on Previous Standards

Condition	ESP removal efficiency	Equivalent emissions at stack exit (mg/Nm^3)
TPP units commissioned before 2009 , Capacity <210 MW	95%	350
TPP units commissioned before 2009 , Capacity <210 MW	97%	150
TPP capacity units commissioned on or after 2009	98.5%	100

For policy scenarios, additional PCTs were required to meet the new PM, NO_x and SO_x emission standards—chosen based on applicability and cost constraints described earlier.

Policy Scenario 1 (PS 1): The CEA proposed a phasing plan for FGD installation in March 2017 for 62% of the existing installed capacity, for the time period 2019 to 2023 (CEA, 2017 a). This phasing plan is likely to have factored in grid feasibility and land constraints in TPPs. Although 68 GW of current installed capacity is not included in CEA's FGD plan, PS 1 has also included compliance for all existing plants. By 2025, all plants that are operational as per the power sector model analysis are modelled to install and run appropriate PCTs to comply with respective MoEFCC targets.

Policy Scenario 2 (PS 2): The second policy scenario is targeted to reduce adverse health effects. Recent studies indicate that more health benefits can be accrued in air-sheds with lower $PM_{2.5}$ concentrations (Pope, Cropper, Coggins, & Cohen, 2015). Based on the district-wise ambient $PM_{2.5}$ concentration derived from satellite data for 2015, and TPP's contribution to $PM_{2.5}$ concentration in that air shed, a phasing plan was modelled targeting plants in those districts first. TPPs in districts where ambient $PM_{2.5}$ concentration was below 30 μg/m^3 were targeted first (between 2019 and 2021). Hence, a higher installed capacity was targeted first (Table 7). To account for grid feasibility, we assumed that any district with more than 3 GW capacity could not incorporate controls in a short period of time. Plants in districts with greater than 3 GW capacity would install controls in 2020. One more year was given for compliance for plants in districts where there was a high contribution by TPPs to ambient $PM_{2.5}$ concentration (by 2021)[11]. All remaining plants were modelled as complying with the last deadline in the CEA phasing plan, i.e., 2025.

A comparison of the year-wise targeted installed capacity is given in the table below:

Table 7: Phased Implementation of Standards in Policy Scenarios

Year	PS 1 targets (GW)	PS 2 targets(GW)
2019	5	15
2020	11	26
2021	45	50
2022	30	
2023	15	
2025	All remaining (68 GW)	Remaining (83GW)

[11] Contribution from TPPs in each district was evaluated using the CAMx model in the base year.

3.3 System Level Costs and Benefits for PCT Installation

To estimate the system level cost and benefits of implementing the emission standards, the study accounted for investment, operating and maintenance costs of PCTs for every active unit between 2015 and 2030. Further, the economic penalty of impact on TPP performance such as reduction in boiler efficiency and increased auxiliary consumption were also captured[12]. The location specific and disaggregated emission load trajectories (2015–30) under different policy scenarios were used to estimate the change in $PM_{2.5}$ concentrations due to reduction in TPP pollution. This was translated to avoided mortality and morbidity. The health impact was estimated using the Global Burden of Disease estimation approach (HEI, 2010; Pope, Cropper, Coggins, & Cohen, 2015; Gunatilake, Herath; Ganesan, Karthik; Bacani, Eleanor, 2014). The value of statistical life was informed by detailed literature review, and used to monetise the health estimates. The following section provide further details.

Costs of Implementing Emission Standards

Literature review and stakeholder engagements informed capital and O&M costs for PCTs used in this analysis. We modelled 14 discrete PCTs including three measures which were a combination of two control options. We considered PCT costs in INR/kg of pollutant removed, derived from total costs [Refer Annexure C for illustrative representation]. For existing plants, the capital investment component was normalised to the remaining plant life during 2015–30, while the running cost components were annualised. In new plants, capital costs were normalised to the years of operation in the time period of interest (till 2030), and then annualised. Based on the results of the emission trajectories at the unit level, we estimated costs as a product of the quantity of emissions removed in each unit and the cost per kg of pollutant removed.

Health Benefits

Long-term exposure to ambient fine particulates ($PM_{2.5}$ concentrations) has been associated with increase in risk to all-cause diseases and cardio-vascular mortality. Further studies of health costs by the US-Environment Protection Agency (USEPA), indicate that nearly 90% of health costs are associated with increased risk of mortality and morbidity (Pope, Cropper, Coggins, & Cohen, 2015). For this study, hence, the focus of analysis was to estimate the avoided mortality and morbidity due to $PM_{2.5}$ reduction.

For this analysis, Urban Emissions used its Comprehensive Air Quality Model with Extensions (CAMx) for dispersion modelling[13]. This Eulerian photochemical dispersion model is suitable for integrated assessments of gaseous and particulate air pollution due to its modularity in evaluating physical and chemical processes, and for apportioning the contributions for single or multiple sources to the receptor regions. In this analysis, ambient $PM_{2.5}$ was modelled for all emissions from coal-fired TPPs. The model captured the primary PM contributions and the secondary contributions from SO_x and NO_x emissions to the ambient $PM_{2.5}$ concentrations.

[12] The average coal cost is around INR 0.18/MJ and real costs for average power from the model was estimated to be around INR 1.8 to INR 2 /kWh during 2015-2030.
[13] CAMx is an open-source atmospheric dispersion model. The model and its working manual is available @ http://www.camx.com. The dispersion model is driven with meteorology processed using WRF meteorological model (available @ http://www.wrf-model.org) with inputs from the NCEP reanalysis fields (available @ http://www.cdc.noaa.gov/cdc/data.ncep.reanalysis.html).

In order to analyse the health benefits on implementing new emission standards, the gridded decrease in concentration of $PM_{2.5}$ due to PCT installations in TPPs was estimated.

Equation 3

$$\begin{array}{l} Mortality\ Avoided \\ \quad Annually \end{array} = \Delta\, PM_{2.5} \times\ Exposed\ Population \times \Delta ER \times Baseline\ death\ rate$$

25 km X 25 km grid

National mortality rate

Supra-linear Concentration Response Function (CRF) considered on the basis of GBD Assessments

$$\overbrace{ER\ (excess\ risk) = 0.4 \times \{1 - \exp\ [-0.03(PM_{2.5})^{0.09}]\}}$$

Ambient concentrations from satellite data by district

The impact on health was then estimated based on the stylised equation from Pope, et al., 2015, which establishes the relationship of mortality avoided and change in $PM_{2.5}$ concentrations (Equation 3). The Excess Risk (ER) function can follow either linear or supra-linear forms (Pope, Cropper, Coggins, & Cohen, 2015). The linear relation with $PM_{2.5}$ implies that ER per 1 µg/m³ of $PM_{2.5}$ increase is same for any ambient concentrations. However, in a recent study, which consolidated learnings from epidemiological assessments on ambient $PM_{2.5}$ exposure and risk across different regions, it was observed that the ER or concentration response is likely to be supra-linear (concave) at higher levels of exposure (Burnett, et al., 2014) (Pope, Cropper, Coggins, & Cohen, 2015). This implies that a given incremental reduction in ambient $PM_{2.5}$ concentrations ($\Delta PM_{2.5}$) will yield greater benefits in cleaner areas than more polluted areas. This is counterintuitive from how pollution regulation in countries like India target polluted areas to protect the population at risk. In India, where ambient $PM_{2.5}$ concentrations are already higher than the US or European countries, the slope of the ER function, albeit flatter due to a supra-linear form (Figure 9), does not necessarily indicate that marginal benefits of pollution control are lesser due to high population density.

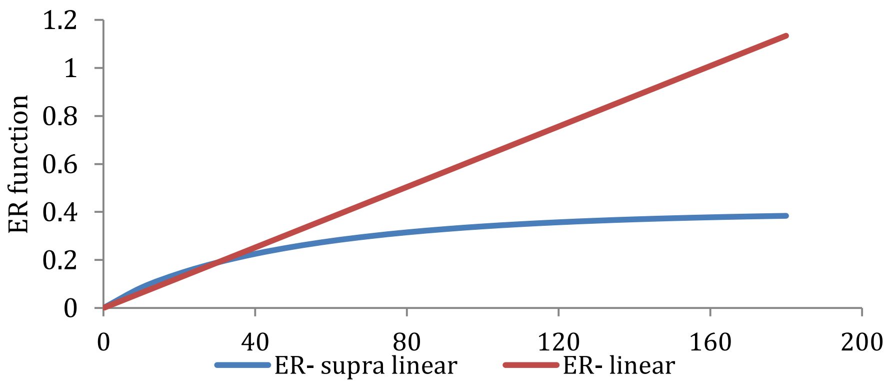

Figure 9: Supra-linear and Linear Form of ER Function

To estimate district-wise ER, satellite data of ambient $PM_{2.5}$ concentrations at the ground level in 2015 (mean average) were used. As per this data, annual average $PM_{2.5}$ ambient concentrations ranged between 5.8 µg/m³ and 108 µg/m³ across districts.

The spatial distribution of the base year population and its projections till 2030 were also required for mortality estimation. The district-wise population data obtained from Census 2011 were spatially mapped for 0.25° grid, using Global Rural Urban Mapping Project (GRUMP), a geo-referenced framework of urban and rural areas (Guttikunda & Jawahar, 2014). The overall population was projected to grow at 1.06% per annum, including differential growth in urban and rural areas.

The annual baseline death rate for India in 2015 was 6.66 per thousand (Gunatilake, Herath; Ganesan, Karthik; Bacani, Eleanor, 2014). During 2015 to 2030, the mortality rate was assumed to decline at a rate of 2.03% annually (derived from historic mortality rate data from World Bank 1960-2015)[14].

Equation 4

$$Morbidity_i\ Avoided\ Annually = \Delta\ PM_{10}\ x\ Exposed\ Population\ x\ DRF_i$$

25 km X 25 km grid

Where *i* – Number of Respiratory Hospital Admission Cases (RHA) or Work Loss Days (WLD)

Inputs:

- $PM_{2.5}$ concentration from Urban Emission's CAMx runs
- 25 km x 25 km grid $PM_{2.5}/PM_{10}$ scaling factor obtained from CSTEP runs based on emission inventory model- Multi-resolution Emission Inventory for China (MEIC, 2018)
- DRF_{RHA} – 1.3 per 10 μg/m^3 change in PM_{10} concentration (Gunatilake, Herath; Ganesan, Karthik; Bacani, Eleanor, 2014) (HEI, 2010)
- DRF_{WLD} – 31.5 days/1000 adults per 10 μg/m^3 change in PM_{10} concentration (HEI, 2010)

Morbidity health endpoints such as RHA and WLD were estimated using Equation 4.

Monetising Benefits

This study monetised avoided premature deaths and morbidity using Value of Statistical Life (VSL) and Cost of Illness (CoI) arrived from in-depth literature studies. Studies in the last decade and a half estimated a wide range of VSLs. Across studies, VSL varies owing to various dimensions like individual risk taking behaviour and individual characteristics such as age, income, gender, race, immigrant status, etc. Thus, there is no uniform VSL and the VSL estimates have to be adjusted for these dimensions (Viscusi W. K., 2011). However, the estimation of VSL across geographic spread, accounting for risk taking behaviour and individual characteristics was beyond the scope of this study. Instead, we considered a value of INR 2.8 crore per life from a recent study (Madheswaran, 2007); this study accounted for risk preferences of over 1000 workers in Chennai and Mumbai based on a hedonic price model. This value is also within range of values reported in empirical research from India in recent

[14] Same death rate is assumed across all districts

decades [Refer Annexure-D]. The reported study value was adjusted to reflect the 2015 base year, since the base year of comparison for costs and benefits is 2015.

For monetising morbidity benefits, the following values were taken as direct benefits transferred based on CoI estimation (Gunatilake, Herath; Ganesan, Karthik; Bacani, Eleanor, 2014):

- Monetary value of each RHA case – INR 13,750
- Monetary value of each WLD (average daily wage in India) – INR 224

Estimating Impact on Tariff

Under the Electricity Act, any costs borne by the power producer owing to change of law can be passed on to the consumer (The Electricity Act, 2003; CERC, 2014). Therefore, the regulatory agencies will now have the task of evaluating petitions for revisions in tariffs owing to PCT installation in TPPs. Given the differentiated impact on TPPs of the emission norms, the costs incurred will also vary. In this regard, this study evaluated the additional impact on tariff for various cases, following the provisions in the Electricity Act, 2003 and Tariff policy, 2006 notified by the Government of India (MoLJ, 2003). According to the Electricity Act 2003, centrally-owned stations with inter-state electricity transmission have to follow the terms and conditions specified by the Central Electricity Regulatory Commission (CERC) (CERC, 2014). In case of generating stations within a state, tariff is determined by the respective state electricity regulatory commissions.

The revised emission standards are specified for vintage and unit capacity. Based on the TPP database, it was seen that increasingly larger capacity units were installed since 2003. Plants installed before 1992 (~37 GW or 135 units) are of old vintage. In these plants, PCTs are economically infeasible due to very high retrofit costs and additional land requirement. Hence this category was not considered for financial evaluation. For plants commissioned between 1992 and 2003, majority of the installations (62 units) were 210 MW. Between 2003 and 2016, 120 units of 210 MW or 500 MW capacities (about 60 each) were commissioned. Among the proposed plants (to be commissioned after 2016), nearly 80% of all units in the pipeline are 600 or 660 MW capacity (CEA, 2016 a; CEA, 2013; CoalSwarm, 2016). Based on the PCT module and TPP database explained above, we assessed four cases for tariff impact (Table 8). The cases developed represent 84% of the likely total installed capacity in 2030 (263 GW).

Table 8: Cases for Financial Assessment of PCT Costs

Case	Description	Representative of (in 2030)	PCT implemented & association removal efficiency	Useful life left (as on 2017)[15]
Case 1	210 MW subcritical unit commissioned in 2002	20 GW	LNB and OFA (52.5% for NO_x), washed coal (30% for PM and 25% for SO_x), LI (55% for SO_x)	10
Case 2a	210 MW subcritical unit commissioned in 2011	135 GW	Upgradation of ESP (99.4% for PM), LI (55% for SO_x), SCR (90% for NO_x)	19
Case 2b	500MW supercritical unit commissioned in 2011		Upgradation of ESP(99.4% for PM), WFGD (95% for SO_x), SCR (90% for NO_x)	19
Case 3	660 MW Supercritical unit commissioned in 2017	68 GW	ESP (99.6% for PM), WFGD (95% for SO_x), SCR (90% for NO_x)	25

The Levelised Tariff (Cost) of Electricity (LToE) was estimated for each case. Results from this analysis can serve as a benchmark for evaluating tariff increment petitions due to PCTs in future petitions. Annexure D provides details on methodology and calculations for financial analysis.

4. Results and Discussion

This section is divided into three parts: (1) Interpretation of emission standards; (2) Emission trajectories for scenarios considered; and (3) Costs and benefits of complying with new emission standards.

4.1 Interpretation of Emission Standards

The current emission factors for various coal types used in Indian TPPs were estimated following a stoichiometric mass balance approach. Emission factors given in Section 3.1 were normalised to mass flow rates with respect to input energy (mg/MJ_{coal}) for ease of interpretation (Figure 10). The current emission factor of SO_x varies between 316 and 2969 mg/MJ_{coal} based on the type of coal used in TPPs. SO_x emissions from TPPs that use Indonesian coal or lignite emits more than five times of SO_x as compared to domestic coal. The NO_x emission factor for both Indian and imported coals are similar. The current PM_{10} emissions with ESPs vary between 43 and 89 mg/MJ_{coal} for domestic coal, while that with imported coal, it is around 2–11mg/MJ_{coal}, owing to its low ash content.

[15] Useful life of 25 years was considered

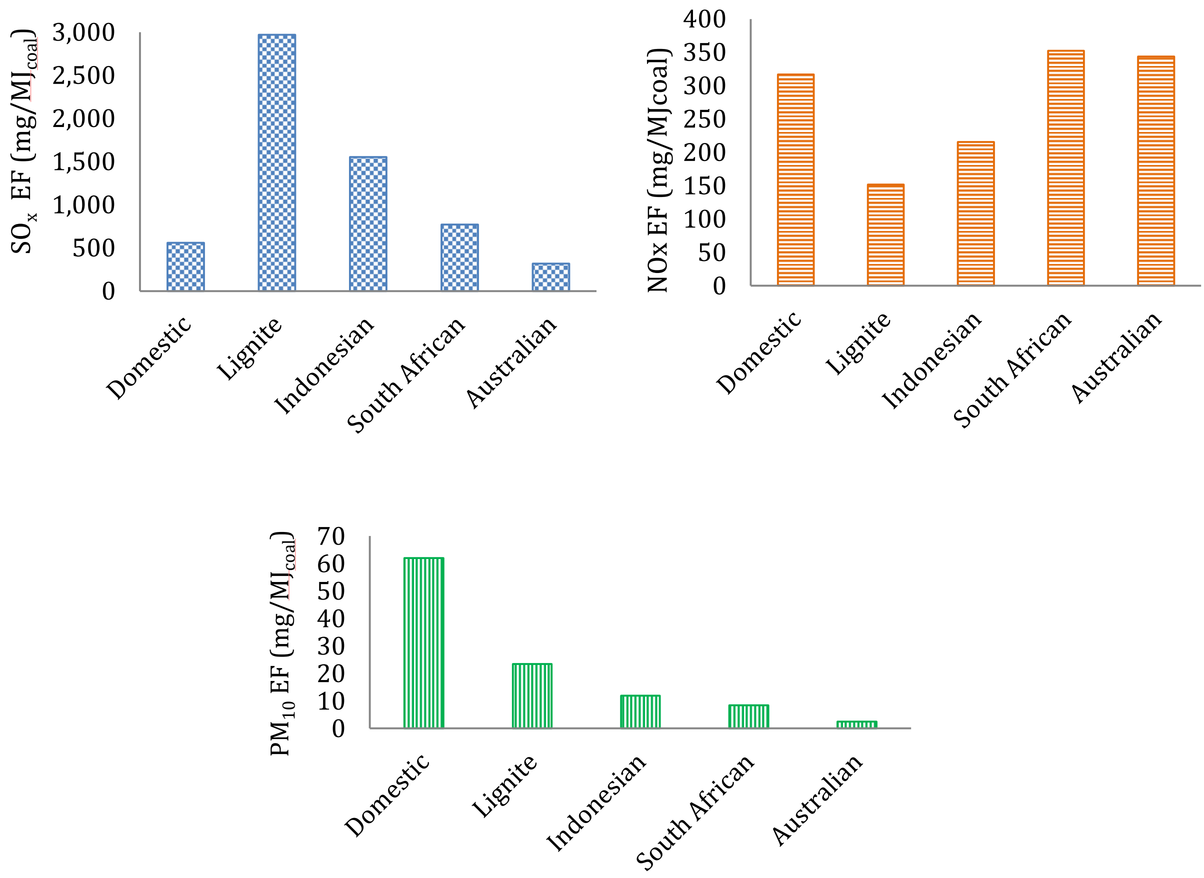

Figure 10: Current Emission Factors (EF) [16]

The new emission standards in concentration metrics were converted into mg/MJ$_{coal}$ using Equation 2 (Table 9).

Table 9: Emission Standards in terms of mg/MJ$_{coal}$

Installation Period	Unit Capacity(MW)	Pollutants concentration (mg/MJ$_{coal}$)			
		SO_x	NO_x	PM_{10}	Hg
before 2003	<500	190.68	190.68	31.78	0.01
	≥500	63.56			
2003 -2016	<500	190.68	95.34	15.89	0.01
	≥500	63.56			
from 2017	All	31.78	31.78	9.53	0.01

Based on the new emission standards and current emission factors, new plants (commissioned after 2016) need to reduce SO_x and NO_x emissions by 95–98% and PM_{10} by 20% (imported coal) to 85% (indigenous coal). The plants commissioned during 2003 and 2016 need to curb SO_x emission by 88–95% and NO_x emission by ~80% to meet the emission standards. Also, these plants need to reduce PM_{10} emission by 20–85% depending on the coal type used. TPPs commissioned before 2003 have to comply with a more relaxed standard as compared to the

[16] The domestic coal type denotes the average coal composition of indigenous sub-bituminous coal type used in Indian TPPs

plants of 2003–16 vintage, and these plants can meet the new standards by reducing their current emission by 30% (PM) and 66% (SO_x).

4.2 Emission Trajectories for Scenarios Considered

Based on the future electricity demand projections, electricity generation from TPPs till 2030 were estimated using the IMRT model. Around 90 GW of additional capacity, including expansion plans and new coal TPPs, were modelled for the 2015–30 time period, to meet the demand (accounting for retirement of 40 years). This is similar to the coal capacity addition plans from CEA's own scenario planning, which accounts for 50 GW of under-construction plants and an additional capacity of 44 GW during 2022–27 (CEA, 2016 b). The IMRT model suggests that in 2030 for a total electricity generation of around 2900 TWh, around 62% will be from coal TPPs. Using state level electricity generation profiles from the model, annual coal consumption for each unit in 2015–30 was estimated. The annual coal consumption in the power sector will double from 515 million tonnes in 2015, to 1023 million tonnes in 2030. The reference emission trajectories till 2030, based on the coal linkage at plant level and derived emission factors, are given in Figure 11.

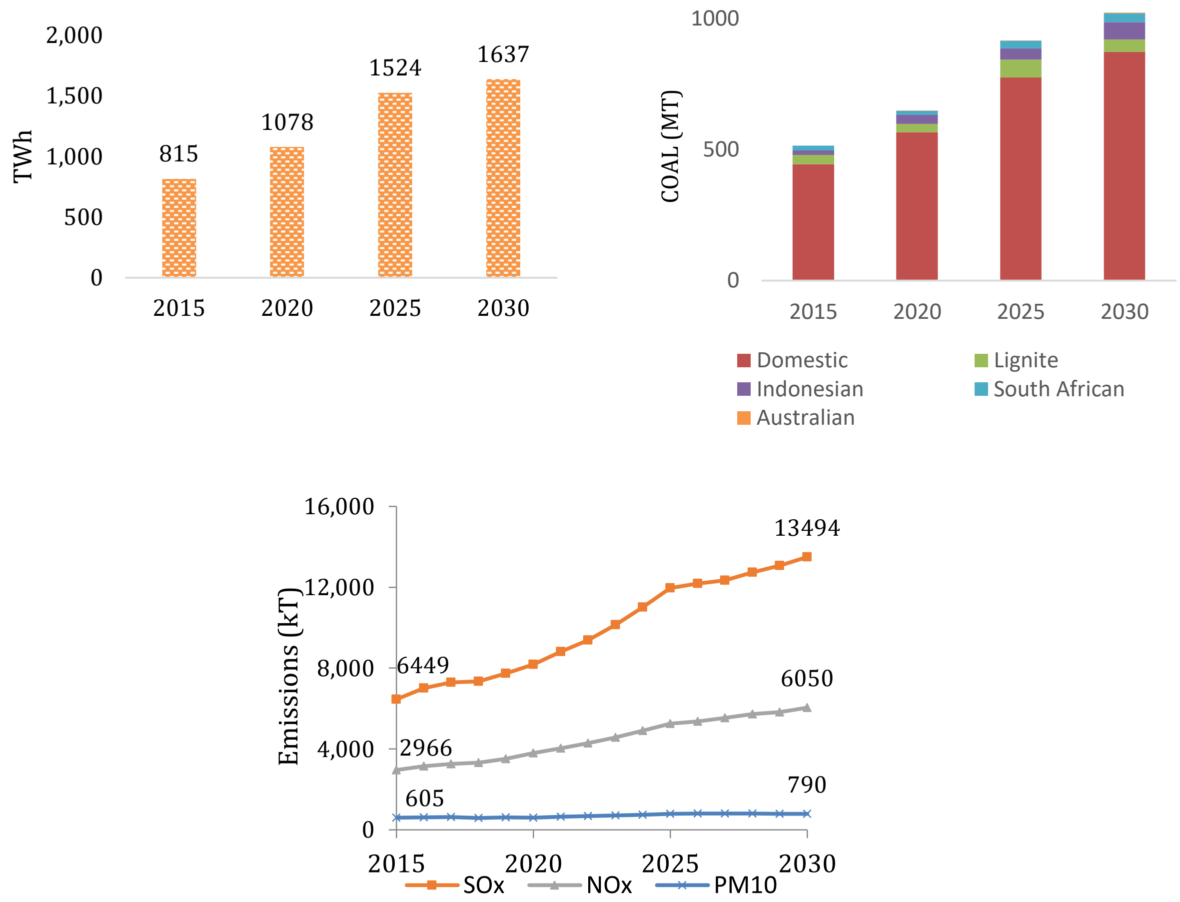

Figure 11: Electricity Generation, Coal Consumption and Emission Trajectories in the Reference Case

As shown in Figure 11, in the reference scenario, SO_x and NO_x emissions will double by 2030 (non-compliance of standards). PM_{10} emissions are expected to increase by ~30%. The smaller rate of increase in PM_{10} emissions can be attributed to ESPs installed in existing TPPs to meet earlier standards[17].

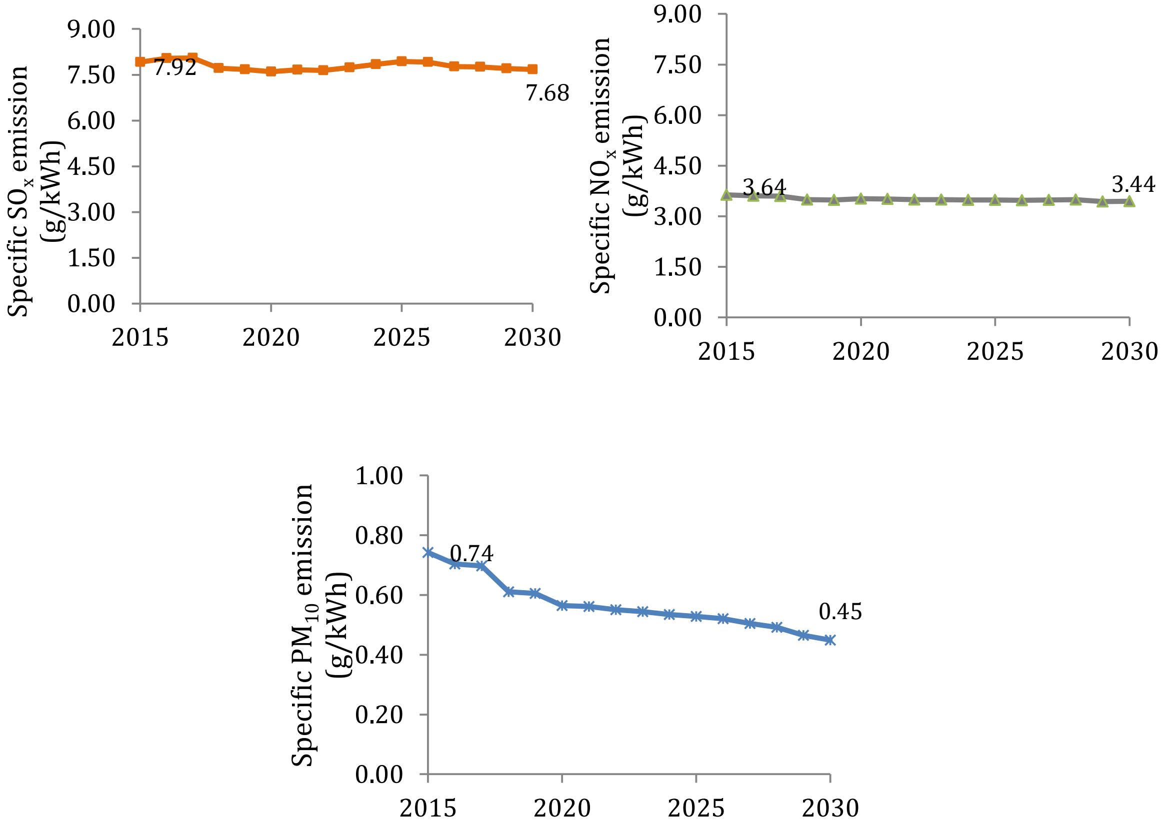

Figure 12: Specific Emissions Trajectories in the Reference Case

Even though the absolute emissions will increase year-on-year, the overall specific emissions of generation remain around the same during 2015 to 2030 (Figure 12). In the reference case, specific pollutant emissions for SO_x, NO_x and PM_{10} in 2015 were 7.92 g/kWh, 3.64 g/kWh and 0.74 g/kWh, and 7.68 g/kWh, 3.44 g/kWh and 0.45 g/kWh in 2030, respectively. A marginal decrease in SO_x and NO_x specific emissions is foreseen in 2030 mainly due to the addition of new plants with higher overall plant efficiency. The specific emission for PM_{10} will reduce by nearly half due to the installation of high performing ESPs in new plants.

Emission Trajectories for Policy Scenarios

The emission trajectories for the reference and two policy scenarios (with additional PCTs to meet the standards) are shown in Figure 13.

During 2019 and 2025, a gradual reduction in emission is seen, reflecting the implementation of PCT phasing plan in existing TPP units. By 2030, with the implementation of PCTs, the SO_x and NO_x emission can be reduced by 95% and 87%, respectively, and PM_{10} increase can be limited by 83%. Complying with the new emission standards will also drastically reduce the SO_x, NO_x and PM_{10} specific emissions in 2030 to 0.36 g/kWh, 0.43g/kWh and 0.08 g/kWh,

[17] A sensitivity analysis on reference emission trajectories was carried out with blended domestic and imported coal in the ratio, 70:30 (typical blending ratio in India). With the blended coal emission factor, the total emissions in the reference trajectory reduced by 6% of the total SO_x emission from TPPs. In other pollutants deviation was marginal.

respectively (Figure 14). For SO_x and NO_x, the intensity drops by 20 times and 8 times (respectively) as the plants didn't have to meet any emission standards earlier.

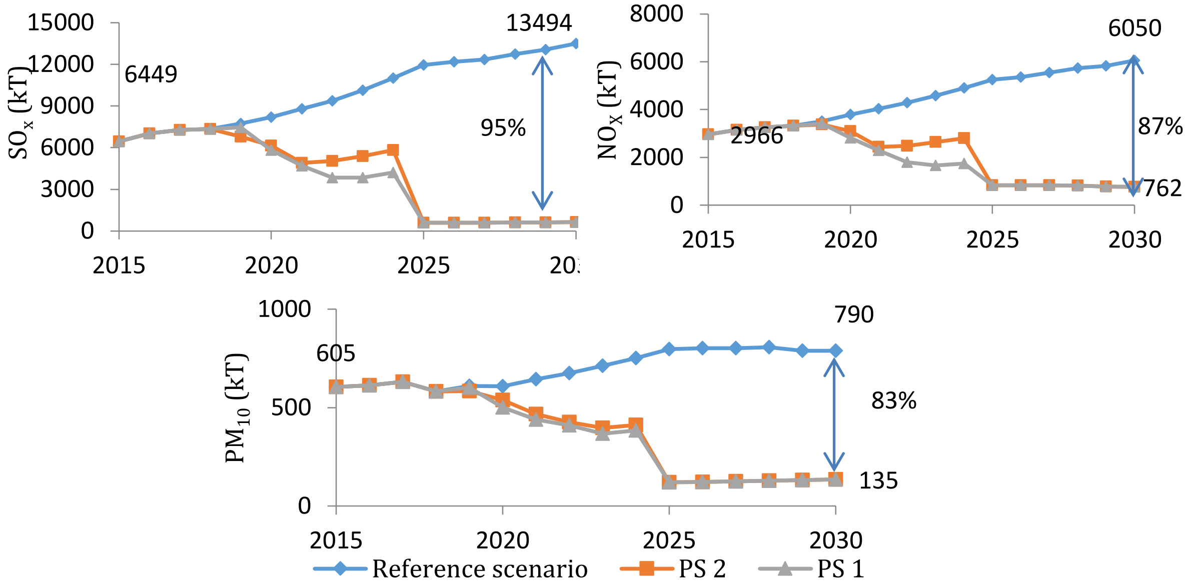

Figure 13: Emission Trajectories for Policy Scenarios

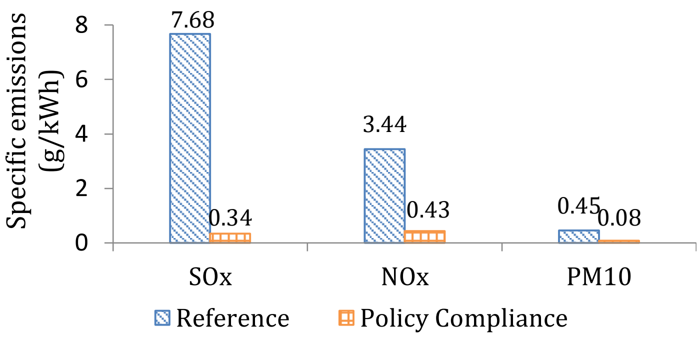

Figure 14: Specific Emissions with and without Pollution Controls in 2030

Costs for Complying with Standards

We estimated the total investment required till 2030 based on the unit-level PCT choices from the applicability matrix and compliance timeframe, specified under each scenario. This included additional expenses such as operational and maintenance costs (O&M)[18] of PCTs, reagent costs and additional costs (plant efficiency reduction and increased auxiliary consumption). The total investment under PS 1 was INR 3,96,200 crore (INR 3,962 billion). Under PS 2, the total investment required was INR 3,91,100 crore (INR 3,911 billion)[19]. Capital investment of INR 2,57,700 crore accounts for 64% to 70% in PS 1 and PS 2, respectively.

[18] O&M costs include annual maintenance expenses, labour costs, auxiliary power consumption and penalty for reduction in overall plant efficiency in terms of additional coal requirement.
[19] There is a marginal difference in total costs between PS 1 and PS 2 since delayed implementation on certain plants leads to lower running costs. Moreover, greater benefits are be seen in PS 2, explained in the following section.

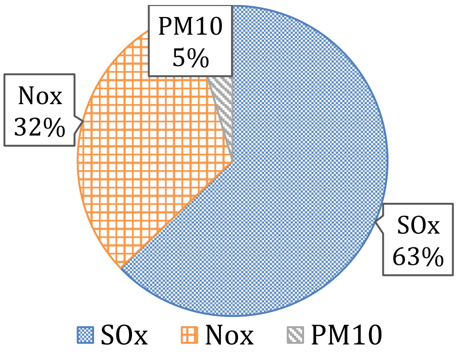

Figure 15: Share of PCT Investment required for SO_x, NO_x and PM_{10} Reduction

The investment required for SO_x PCTs was highest, owing to the high capital cost, as compared to other pollutant controls (accounts for 63% of the total investment) (Figure 15). Privately-owned plants will face the highest costs for meeting standards (over 45%), followed by state-owned (32%), and centrally-owned plants (24%).

Comparison with Other Studies

Recent estimates are available from other research groups and the power producers association. The Centre for Science and Environment (CSE) reported that the total capital investment required for installing PCTs in 169 GW of existing plants (excluded 17 GW of old vintage) is around INR 71,700 crore (Bhati & Ramanathan, 2017). Albeit CSE accounted for the varied costs of PCTs required by different vintage and capacity plants in detail, this assessment did not consider O&M costs, which we estimate will account for at least 30% of the total costs. In their assessment, CSE also reported that TPP units commissioned between 2003 and 2016 can meet NO_x emission standards with cheaper control technologies such as LNB and OFA. Whereas, in our analysis, baseline NO_x concentrations were modelled for each plant. This indicated that only lignite TPP units commissioned between 2003 and 2016 can achieve the NO_x target using LNB (2.5 GW). Since we have compared our weighted average NO_x specific emissions in g/kWh with the values reported by MoEFCC (PIB, 2015), we feel our representation of costs is reasonable and possibly better disaggregated.

Another study by the Association of Power Producers (APP) estimated capital costs required for PCT installation in recent TPPs (commissioned after 2003), and accounted for 186 GW of installed capacity (including 54 GW of proposed TPPs on the anvil). Their capital cost is estimated at INR 2,80,000 crore (Krishnan, 2016). While its order of magnitude is consistent with this study's aforementioned capital cost estimate, APP estimates covered fewer plants and may have over-estimated the market opportunity (we estimated investments required for 263 GW of installed capacity by 2030).

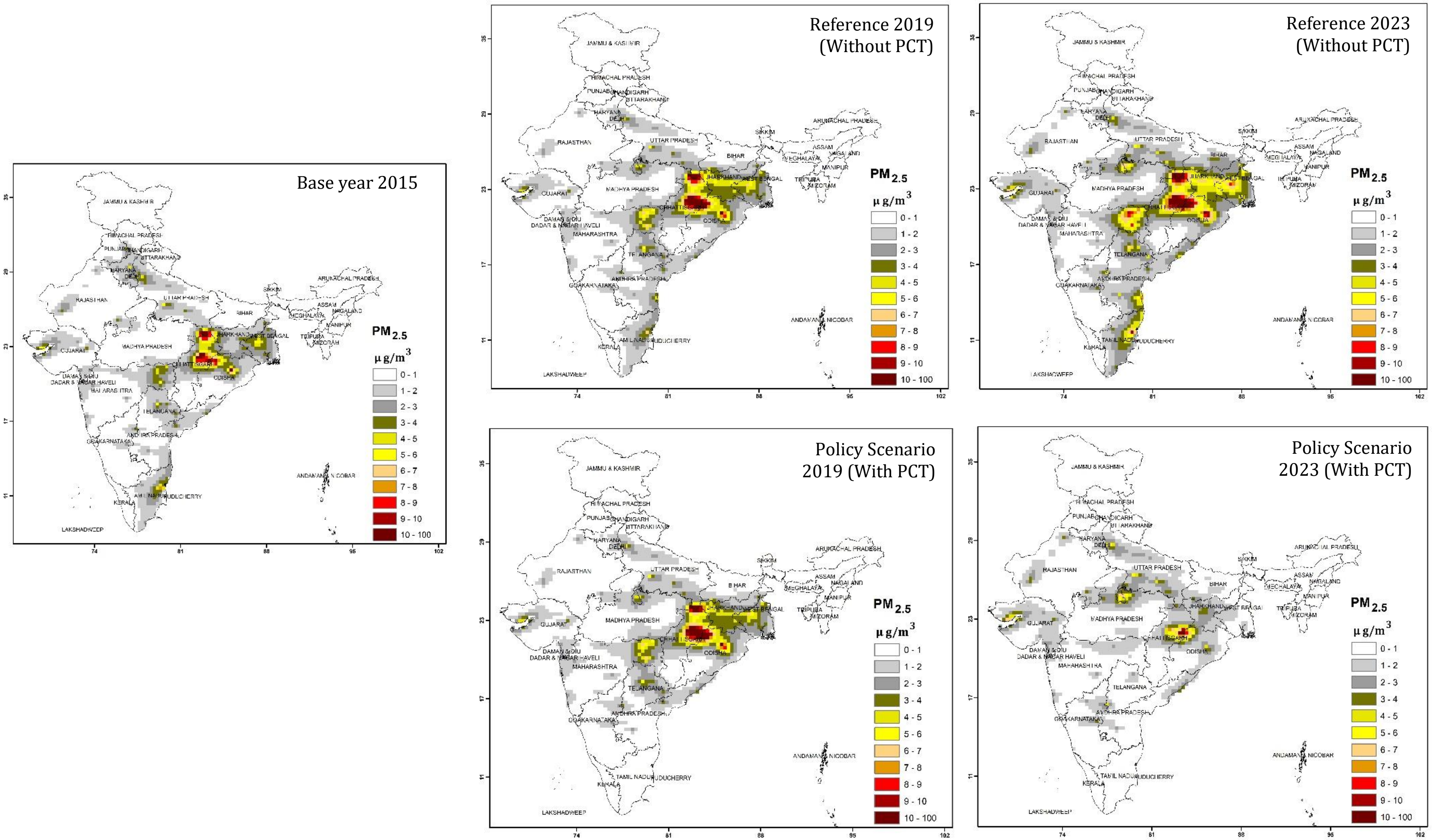

Figure 16: $PM_{2.5}$ Concentration due to TPP Emissions with and without PCT (PS 2)

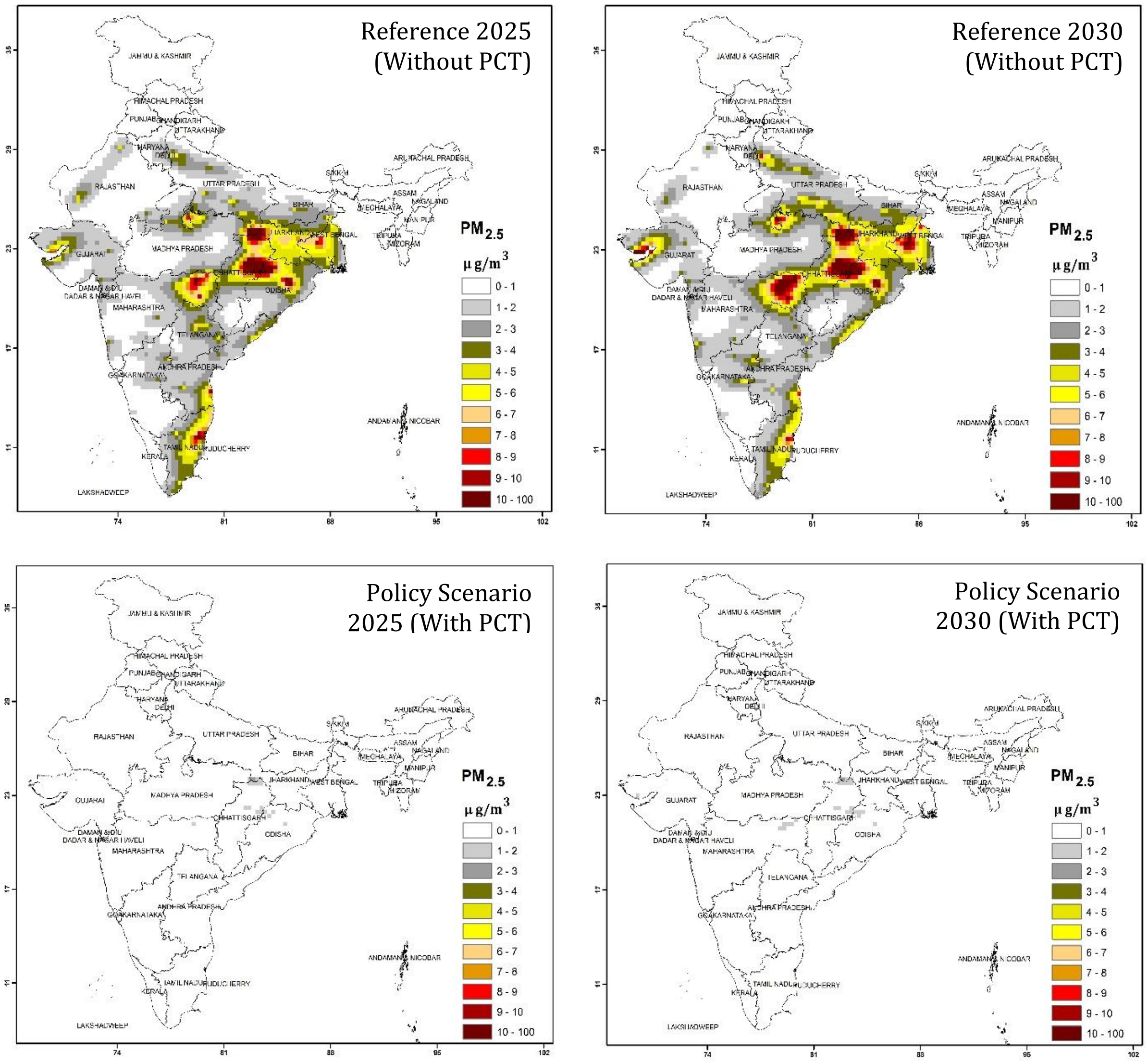

Figure 17: $PM_{2.5}$ Concentration due to TPP Emissions with and without PCT (PS2 & Reference) (continuation)

Benefits on Complying New Emission Standards

$PM_{2.5}$ in ambient air is responsible for major diseases and associated premature mortality (Cropper, Gamkhar, Malik, Limonov, & Partridge, 2012). The CAMx dispersion modelling was used to estimate the change in ambient $PM_{2.5}$ concentration owing to TPP emissions. The population weighted average concentration (attributed to TPP emissions) in 2015 was around 1.21µg/Nm³ and will increase to 2.19 µg/Nm³ in 2030 if standards are not implemented by 2025 (Figure 16 and Figure 17). The $PM_{2.5}$ concentration (from TPPs) was high in states like West Bengal, Chhattisgarh, Tamil Nadu and Maharashtra owing to the larger number of TPPs in these states. Once emission controls are installed, the population weighted average concentration of $PM_{2.5}$ in 2030 will drop to 0.15 µg/m³ (93% lesser than the reference case).

Based on the difference in gridded $PM_{2.5}$ concentrations (annual average) between the reference and policy scenarios, we estimate that around 3.0 to 3.2 lakh premature deaths can be avoided during 2019 and 2030.

Moreover, the health benefits will continue beyond 2030 and were not estimated in this study. From Figure 18, it can be inferred that targeting TPPs in lesser polluted air sheds based on PS 2 phasing plans can save 15,000 additional lives between 2019 and 2025.

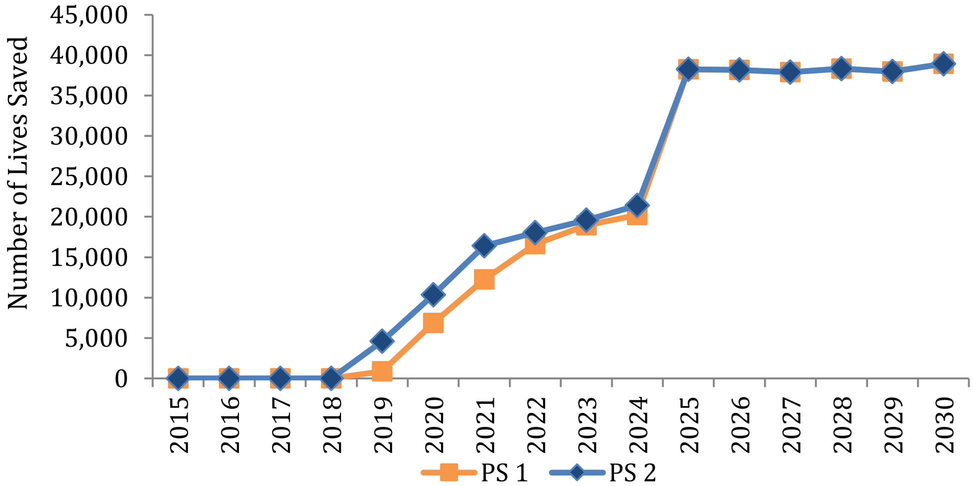

Figure 18: Mortality Reduction in Two Policy Compliance Scenarios

The costs per life saved was estimated to be in the range INR 1.36 crore (PS 2) to INR 1.44 crore (PS 1).

Further, we estimated the avoided diseases or morbidity in terms of RHA and WLD avoided. Implementing PCTs, can avoid about 5.1 crore hospital admission cases due to respiratory disorders (43 lakhs cases per annum) for the period 2019–30. This implies a reduction in 126 million WLD due to poor health from TPP emissions.

Regional Comparison of Costs and Benefits

Most of the existing and planned coal plants are located in the states of Chhattisgarh, Tamil Nadu, Maharashtra and Uttar Pradesh. Hence, these plants will have to incur the largest investments and most states will also see commensurate health benefits. Figure 19 and Figure 20 illustrate the cost and benefit shares in five major states. Over 50% of the total investment will be in five states, namely Maharashtra, Uttar Pradesh, Chhattisgarh, West Bengal and Andhra Pradesh.

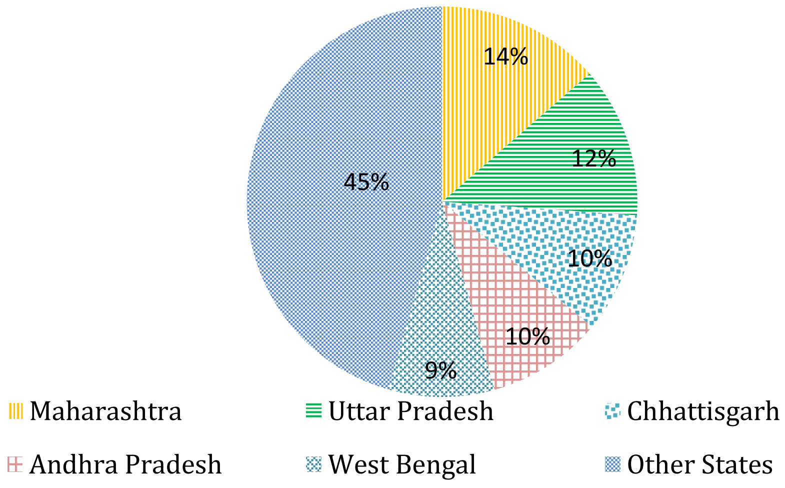

Figure 19: State-wise share of PCT Investment required (PS 2)

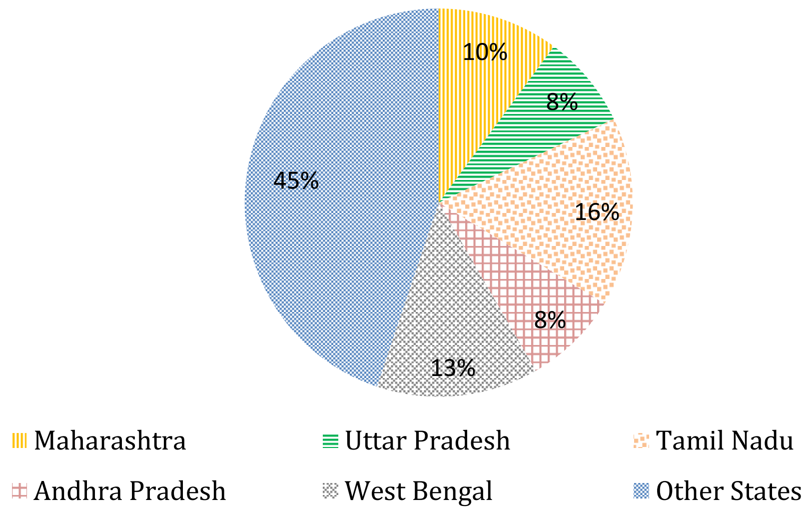

Figure 20: State-wise Mortality Reduction with Emission Standard Compliance (PS 2)

The states with maximum health benefits are Tamil Nadu, West Bengal, Maharashtra, Andhra Pradesh and Uttar Pradesh. Mortality avoided due to TPP emissions are seen to be lesser in Uttar Pradesh as compared with Tamil Nadu despite the former's higher population density. This is due to the excess risk estimation linked to a supra-linear function, wherein the slope is adjusted for districts based on base year ambient $PM_{2.5}$ concentration in 2015. The average ambient $PM_{2.5}$ concentration from satellite data in Uttar Pradesh's districts was around 88 $\mu g/m^3$ where risk was lower, while in Tamil Nadu was ~ 27 $\mu g/m^3$ where risk is greater.

Though Chhattisgarh ranks third in PCT investment, the benefit in this state is relatively lesser than benefits seen in West Bengal. This is mainly attributed to its lower population density. Whereas in West Bengal, with less than 7% of the total investment, it is ranked second in the number of lives saved. This can be attributed to its higher exposed population, and emission controls in Chhattisgarh's TPPs lowering ambient concentrations and exposure. States such as West Bengal, Tamil Nadu, Jharkhand and Chhattisgarh have the highest morbidity benefits. The cumulative regional impact on mortality and morbidity is depicted in a grid-wise plot (Figure 21).

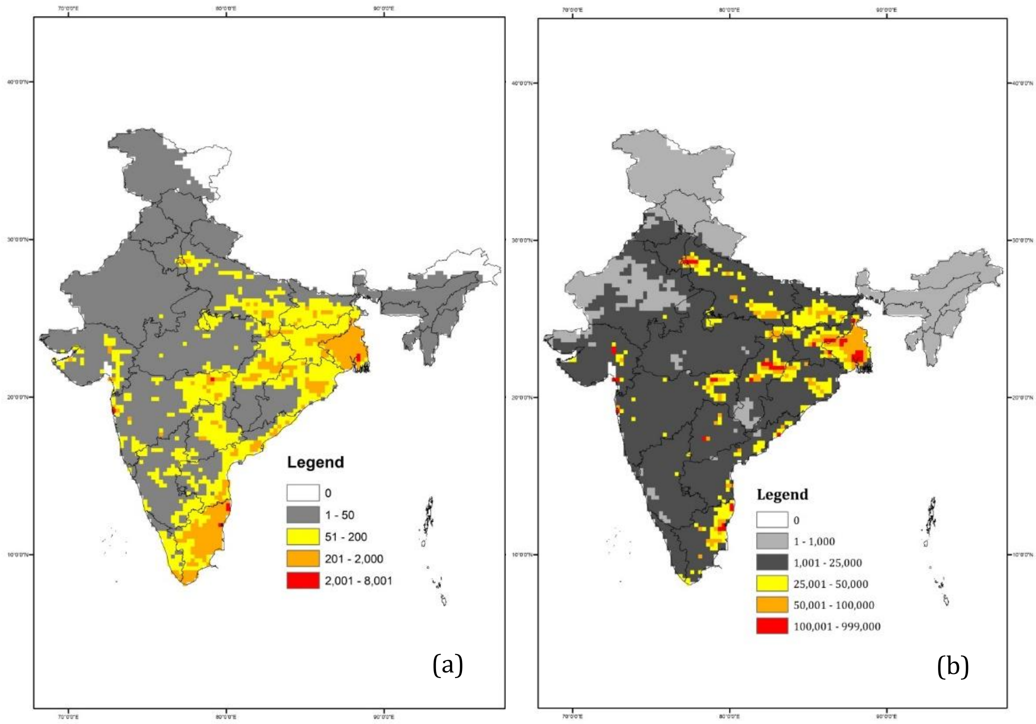

Figure 21: Avoided Cumulative Mortality (a) and RHA (b) till 2030 with Implementation of Emission Standards (PS 2)

Benefit Cost Analysis

This study evaluated the costs of and benefits from implementing the emission standards. The monetised benefit of avoided premature deaths is estimated to be INR 8,88,038 crore during 2015 to 2030. Further costs avoided due to reduction in RHA and WLD was estimated to be INR 74,184 crore [INR 71,367 crore (RHA) and INR 2,817 crore (WLD)]. The total health benefit was monetised to be INR 9,62,222 crore by 2030. However, when the monetised benefit annually was plotted against the annual investment for phased implementation of emission controls, benefits outweighed investment in 2019. This indicates that India can accrue significant economic gains by implementing emission standards for TPPs in a time bound manner.

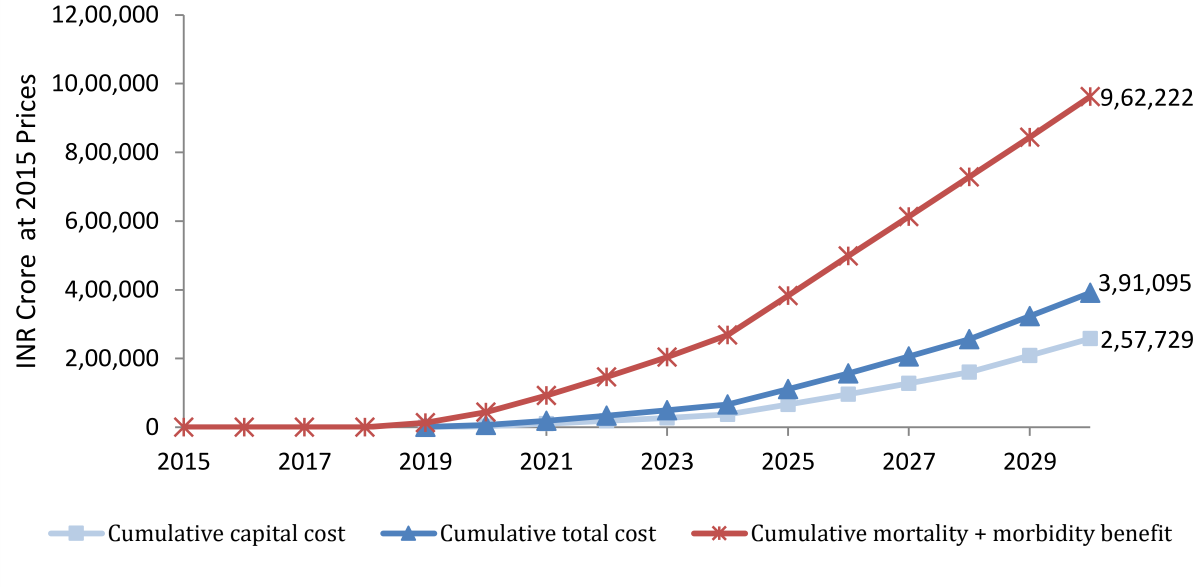

Figure 22: Benefit vs. Cost Analysis of New Emission Standards in TPPs (PS 2)

The analysis indicates that in order for estimated health benefits (lives saved, RHA & WLD) and estimated costs to 'break-even' by 2030, premature mortality can be valued at up to INR 99 lakh per life saved. This translates to around 100 times average per capita income in India in 2015. This ratio is lower when compared to USA valuation –150 times the average per capita income[20] (United States Environment Protection Agency).

Estimating Impact on Tariff

This section estimates the incremental increase in electricity tariff because of PCTs. We estimated the generation cost (with and without PCTs) for four representative cases, as described in the methodology section. In older plants, which use low cost control options, the tariff increases by around 9%. In newer and larger units, higher investment is needed to install high performance control equipment, leading to tariff hikes of 20% to 25%. Evidently, there is a considerable increase in the electricity tariff [Refer Section 2.3 and Annexure-D for further details].

Table 10: Cost Implications of PCT Implementation in Coal Power Plants

Cases	Generation cost without PCT (INR/kWh)	Generation cost with PCT (INR/kWh)	Increase in generation cost (INR/kWh)	Percentage increase (%)
Case 1	2.74	2.99	0.25	9
Case 2a	3.23	3.92	0.69	21
Case 2b	2.92	3.65	0.73	25
Case 3	3.27	3.89	0.63	19

From the analysis, we inferred that case 2 plants (or units installed during 2003–16) will face the highest impact on tariffs. This is because of the high upfront costs of the PCTs required to meet the stringent standards, and lesser time to recover the investment from tariff increase. Also, as shown in the Methodology Section, case 2 plants account for the highest share of installed capacity (over 50% of total installed capacity). Therefore, tariff revision petitions from these category units are likely to be the highest.

[20] USEPA's default VSL for monetising benefits at $7.4 million (INR 4.8 crore) per life in 2006

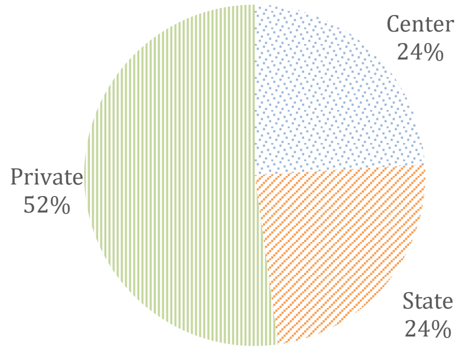

Figure 23: Percentage Share of Ownership of Plants in 2003–16 Vintage

Of these plants, around 52% is privately owned (Figure 23). The state and centrally owned plants may find it easier to meet the upfront costs of PCTs via planned budgetary allowances. However, individual power producers in the private sector will find it challenging to front the large amount of PCT investment required.

The higher capital investments for SO_x and NO_x controls, as well as additional regent costs, drive up the overall costs for implementing the standards. Further, since lesser time is available to this vintage of plants to recover investments, tariff is higher (increase of 20% to 25%) in this category as compared to Case 3 plants. In Case 1 plants, we anticipate an increase of around 9% (0.28 INR/kWh). The tariff increase in this case is significant despite the less costly PCTs due to a lower recovery time. Also, it is important to note that in plants that need to install WFGDs (Case 2b and Case 3), a considerable reduction in the additional cost incurred is possible with the development of synthetic gypsum—a by-product from WFGD. The FGD gypsum can be used in cement production, road construction, and agriculture to improve soil properties. The tariff in this case can be limited to INR 3.82/kWh (~17%).

Comparison of Estimated Tariff with Other Studies

CSE estimated that the average tariff increase without accounting for O&M investments would be around INR 0.20–0.35/kWh (Bhati & Ramanathan, 2017). Meanwhile, APP which likely accounted for high capital intensive options, estimated tariff increase in the range of INR 0.50/kWh to INR 1.25/kWh (Krishnan, 2016)[21]. This study's financial cases for tariff assessment are comparable with our estimates and cover a wider range of cases in a consistent manner.

Impact of PLF on Tariff

The impact of PCT installation on generation tariffs for plants operating at lower PLFs is significant. We estimated that the base tariff (without PCTs) for plants operating at lower PLF (50%) is possibly already much higher—by INR 0.7/kWh (Case 1) to INR 0.97/kWh (Case 2b). This implies that these power producers are already facing a 27–33% increase in generation costs. The major reason for lower PLFs in TPPs is the lack of continuous coal supply, increased maintenance time in older TPPs, and issues of surplus power in the grid (Mukherjee & Tripathy, 2017) (Equitymaster, 2018). According to a Reuters analysis, over 50 TPPs based on coal or gas are operating at lower PLFs (30–50%) (Mukherjee & Tripathy, 2017).

With the introduction of PCTs in these plants, the difference in tariff will be compounded, and will be as high as INR 1/kWh (Case 1) to INR 2/kWh (Case 2b). Therefore, installation of PCTs in

[21] Further, a news report informed by the Minister for Power reported that the tariff can increase by INR 0.62-0.93/kWh in the first year of plant's operation with PCTs (PTI, 2018).

plants operating at lower PLFs will put them under more financial stress. Hence, in plants of relatively newer vintage, PCT installations will be financially viable only if measures to improve PLF are undertaken. For older plants operating at the bare minimum technical PLF, policy guidelines that mandate shutdown plans, especially in winter months when emissions may not disperse, would be economically more feasible than installing PCTs. Seasonal shut down plans have also been deployed in China (Lelyveld, 2017). Similar allowances have also been considered in the European Union (Wynn & Coghe, 2017). These guidelines can serve as a template for the Indian context.

4.4 Summary and Policy Recommendations

This study has shown that the MoEFCC's new standards would imply that SO_x emissions from individual TPPs will reduce by 67–95%, NO_x by 41–95% and PM_{10} by 50–85% across plants of different unit capacity and vintage. We estimated that the total investment for installing and operating PCTs till 2030 will be around INR 3,96,200 crore. However, the benefits accrued include avoiding over 3 lakh premature deaths and morbidity reduction. When monetised, the benefits outweigh cumulative investments. Hence, the standards if implemented in a time bound manner can offer considerable social benefits.

Possible policy interventions to address implementation bottlenecks, like firming up tariff revisions guidelines, and financing options for managing high upfront costs, are provided below:

1. Pass tariff onto consumers
   The Electricity Act mentions recourse to power producers in cases where tariff revisions are necessitated by a change in law, such as the new emission standards. Based on the financial case analysed (including capital and variable costs), we propose the following options to pass tariff onto consumers:
   a. State Electricity Regulatory Commissions (SERC) and CERC include an allowance in the new tariff guidelines (2019–24) for plants commissioned between 2003 and 2016 to avail a tariff hike of up to INR 1/kWh for 5 years, or up to INR 0.7/kWh for 10 years.
   b. SERCs and CERCs include an allowance provision of up to INR 8.5 lakhs/MW per annum, for 5 years, for older units (Case 1) to recover their PCT investment. This would be similar to the annual allowance provision in older guidelines given to old plants for cost recovery of life extension activities (INR 7.5 lakhs/MW per annum) (CERC, 2014).

2. Provide one year grant window or subsidy scheme
   Since upfront costs will likely be a serious barrier in implementing the standards in a time bound manner, the government can consider an enabling grant corpus or a subsidy scheme. Providing a one-year window for availing a grant of INR 93,500 crore can support the PCT capital investment needed in plants commissioned between 2003 and 2016 (or 37% of the total capital investment). Plants that seek this may not be entitled to the tariff revisions owing to increased capital investments. However, they can seek tariff revisions based on allowance of up to INR 18 lakhs/MW per annum toward variable or operating cost of PCT (limiting the end tariff increase to 14%).

3. Enable additional revenue for new plants
   Newer plants will have to compete in the electricity market with higher tariffs. A loan interest waiver or lower loan interest rate for PCTs, to incentivise quicker uptake, can have only a marginal effect on limiting tariff increase; tariffs will still increase by around 17%. Meanwhile the development of a synthetic gypsum (a by-product from FGD) market

in India can provide additional revenue for new plants. Synthetic gypsum can be used as a raw material in cement and glass manufacturing industries, or as a construction material. This could limit the increase in tariff to 15% (approx. INR 0.5/kWh increase in tariff).

Lastly, the government needs to address other concerns such as lack of domestic PCT manufacturing capacity, limited technology providers in India, and the delays in procurement and installation of PCTs (up to 2 years). One possible solution could be the removal of tax levies for imported PCT equipment during a five-year window. Further, since this is an industry-wise mandate, shutdown time for installation of PCTs in several plants and PCT procurement plans, need to be evaluated and scheduled from a grid-stability perspective. Furthermore, select plants with stranded capacity or financial stress could be allowed explore options to operate during monsoon seasons and face closures in winter months.

Limitations of this Study

Uncertainty on power plant operating conditions

The combustion conversion factors for carbon, hydrogen, sulphur and nitrogen in coal were assumed to be constant in the mass balance analysis. These conversion factors are a function of boiler characteristics such as temperature and pressure, and excess air fed to the boiler. These can also be modelled dynamically or measured at the flue stack (via CEMS). This would reduce the uncertainty on baseline emission factors, and by extension, the choice of PCTs and costs.

Data gaps in power plant data

The data on coal linkages for 20 GW installed capacity was not available. In this case, the nearest coal fields were considered as the coal source. Better data on coal usage and composition can enable more robust estimation of emission trajectories and choice of PCTs.

Unavailability of all sources emission inventory and regional baseline health effects

The study used a static baseline death rate based on nationally reported numbers. District-wise death rate for the base year may affect the estimated values. Similarly, there is no emission inventory and projection available for all point sources till 2030. Hence tracer runs on CAMx were used that isolated the effects of TPPs on ambient $PM_{2.5}$ concentrations. With improvements in data availability and modelling approaches, the estimation of the regional variation can be strengthened.

Annexure-A

CSTEP Power Plant Database and Ancillary Model Input Data

Coal Plants

Coal power plants in India were classified based on vintage and unit capacity, specified in emission standards for carrying out the current study, conducted at CSTEP.

As shown in Table 3, a majority of the TPP units before 2003 were less than 500 MW capacity. It is also seen that increasingly larger capacity units have been installed since 2003. Around 72% of the total existing installed capacities are between 2003 and 2016. In the proposed plant category (to be commissioned after 2016), nearly 80% of all units in the pipeline are 600 or 660 MW unit capacity (CEA, 2016 a; CEA, 2013; CoalSwarm, 2016). Majority of the high capacity (≥500 MW) plants are privately owned.

Non-coal Power Plants

The CEA database was used to baseline generation, installed capacity and efficiency for nuclear, gas and diesel power plants (Table 11). The installed capacity of renewables was benchmarked against data provided by CEA (2016) for which the model identified representative plants.

Table 11: Non-coal Power Generation Installed Capacity used in IMRT

Ownership	Gas	Diesel	Nuclear	Hydro	Renewable	Total (GW)
Central	7	0	7	12	0	26
State	7	0	0	30	2	39
Private	11	0	0	3	55	70
All India	25	1	7	45	57	135

Based on progress against India's three-stage civil nuclear plans, we accounted for around 22 GW of nuclear installed capacity being operational by 2030. Meanwhile, the CEA has plans for an additional 15.9 GW of large hydro power plants. Further, based on the lower investment cost specified for solar plants, the 175 GW target of the NDCs is also achieved by 2030.

Coal Linkages

Data on type of coal linked to TPP units were collected from various literature sources (CEA, 2015; CoalSwarm, 2016). Few assumptions were made wherever data were not available, such as choosing nearest coal fields or ports. The major domestic coal suppliers are SECL and MCL, and that among imported coal is Indonesian coal. In practice, to limit PM emissions, the MoEFCC had stipulated that ash content in coal used at TPPs can't exceed 34% - hence several plants blend domestic coal with imported or lower ash coal.

Inputs on Plant-level Efficiency

Efficiency is the ratio of the energy generated to the total heat units of fuel consumed. Station heat rate (kCal/kWh) is the energy expended to obtain a unit of useful work (Nowling, 2015). The efficiency is the inverse of heat rate. Efficiency of a thermal power plant can be calculated by using Equation 5.

Equation 5

Efficiency = (Fuel emission factor/ specific emission factor of plant)*conversion factor[22]

Using the above equation, we back calculated the plant level efficiencies of coal TPPs in the CSTEP database. We triangulated the plant level data against emissions and generation data provided in the CO_2 database for historic years (2010–15). Based on the equation given above, the calculated efficiencies assumed for power sector modelling averaged around 30.2% across existing TPPs. This is marginally lower than the 32% average efficiencies calculated from the average station heat rate reported for coal plants in recent years. Around 5% of the installed capacity or 56 units had efficiency lesser than 30%. Around 81% of these inefficient plants were state-owned and the remaining were owned by the centre or private power producers.

Resource Availability Inputs

The IMRT model was provided state-level renewable energy resource potential as per estimates of the Ministry of the New and Renewable Energy.

Table 12 summarises the all India estimate by resource category.

Table 12: Renewable Energy Potential (GW)

Solar	Wind	Small Hydro	Biomass
749	102.8	19.7	25.1

Source: (Ministry of New and Renewable Energy, 2017)

Further, our analysis also accounted of coal resource availability driven by production and costs, and defined in INR/PJ terms annually for different domestic and imported coal types. We used overall production targets from CIL for domestic coal till 2020 (estimated at around 700 MT for non-coking domestic coal) and assumed these will be realised by 2030 (CCO, 2015; Saha, 2017). Similarly, using historic trends coal import availability was projected to grow by around 3.5 times to around 381 MT (Indian Bureau of Mines, 2015). Based on available data, coal cost at pithead was assumed to range from INR 720/tonne (GCV range 3400-3700 kcal/kg) to INR 2900/tonne (SCCL coal of GCV 5110 kcal/kg) (CIL, 2016; The Singareni Colleries Company, 2017). Further, transport costs based on travel distance from pithead to TPP were also factored in as the location of the TPP units were known. This ranged from INR 205/tonne of coal (distance of 1–125 km) to INR 1607/tonne of coal (distance of 1100–1200 km) (Railway Board, Ministry of Railways, 2015).

[22] CEA reported a fuel emission factor of 90.6 g CO_2/MJ in its emission database updated in 2016. Station level specific emission averaged at 1.04 t CO_2/MWh for coal plants. Conversion factor (1 MWh=3600J)

Annexure–B

Estimating Baseline Emission Factors for Coal TPPs

Coal types majorly used consist of 9 domestic and 3 imported. The nine major coal fields in India are Western Coal Field Limited (WCL), Eastern Coal Field Limited (ECL), Central Coal Field Limited (CCL), Mahanadi Coal Field Limited (MCL), Northern Coal Field Limited (NCL), South-Eastern Coal Field Limited (SECL), Singareni Collieries Company Limited (SCCL), Bharat Coking Coal Limited (BCCL), Neyveli Lignite Corporation and Kutch Lignite. The imported coal majorly used in India are Indonesian, South African and Australian. The composition and calorific value of 9 domestic coal types and 3 imported coal types are given in Table 13 and Table 14, respectively.

Table 13: Coal Composition and Gross Calorific Value for Indian Coal Types

Component	ECL	NCL	CCL	SECL	WCL	MCL	SCCL	BCCL	Lignite
Carbon (%)	46.9%	40.3%	42.3%	50.2%	42.1%	35.6%	46.2%	43.0%	26.0%
Hydrogen (%)	3.0%	2.6%	2.7%	3.1%	2.9%	2.5%	2.9%	2.6%	2.3%
Sulphur (%)	0.5%	0.3%	0.5%	0.5%	0.7%	0.5%	1.0%	0.4%	1.5%
Nitrogen (%)	1.2%	0.8%	0.9%	1.1%	0.9%	0.9%	0.9%	1.0%	0.2%
Oxygen (%)	10.5%	5.5%	9.5%	8.2%	4.3%	7.3%	9.3%	6.5%	16.3%
Moisture (%)	5.3%	9.4%	7.8%	6.1%	7.5%	8.2%	5.2%	1.0%	47.0%
Ash (%)	29.6%	37.4%	33.0%	28.0%	37.8%	40.9%	31.4%	41.4%	7.0%
Hg (%)	8 x 10^-6 %	6 x 10^-6 %	22 x 10^-6 %	10 x 10^-6 %	12 x 10^-6 %	20 x 10^-6 %	12 x 10^-6 %	8 x 10^-6 %	8 x 10^-6 %
GCV (kcal/kg)	4450	3835	4111	5008	4562	3570	5110	4875	2234

Table 14: Coal Composition and Gross Calorific Value for Imported Coal Types

Component	Indonesian	South African	Australian
Carbon (%)	62.37	74.99	70
Hydrogen (%)	5.02	5.16	4.80
Sulphur (%)	2.21	1.31	.50
Nitrogen (%)	0.96	1.88	1.70
Oxygen (%)	9.71	7.04	6.30
Moisture (%)	9.68	1.09	2.30
Ash (%)	10.05	8.53	14.40
Hg (%)	12 x 10^-6 %	8 x 10^-6 %	8 x 10^-6 %
GCV (kcal/kg)	6290	7540	6990

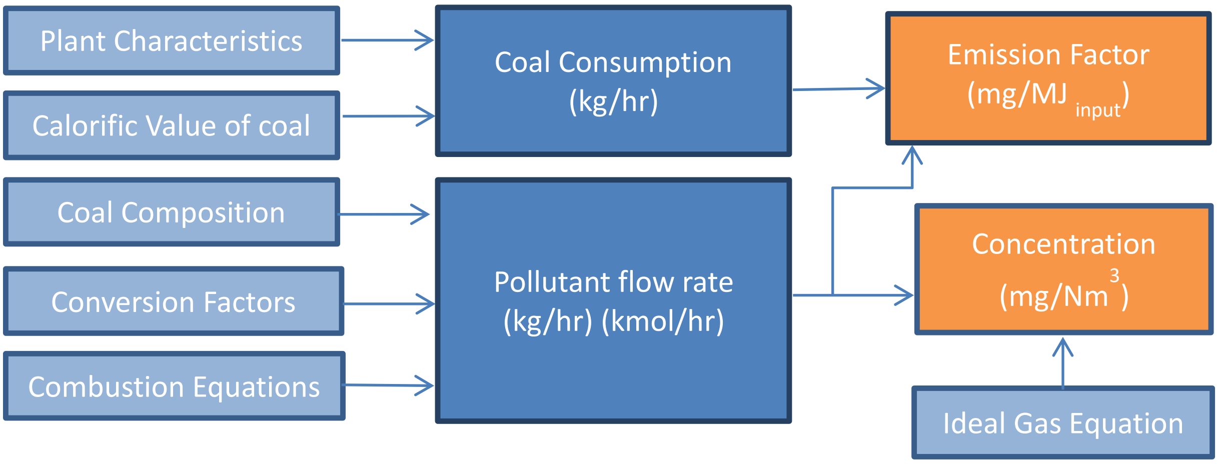

Figure 24: Schematic Representation of Mass Balance Analysis

To estimate the variations in emissions pertaining to coal compositions, a typical TPP unit of 210 MW capacity and plant operational parameters such as Plant Load Factor (PLF) of 70% and overall plant efficiency of 33% (Indian average as per CEA data base) was considered for pollutant estimation. The schematic representation of mass balance calculations is shown in Figure 24.

The current concentration of pollutants emitted from coal TPPs was estimated from volumetric flow rate of the flue gas and the mass flow rate of the pollutants at stack exit, as given in Equation 6.

Equation 6

Concentration $\left(\frac{\text{mg}}{\text{Nm}^3}\right) = \frac{\dot{M}_i}{\dot{V}}$

Where,

$\dot{M}_i$ – Mass flow rate of pollutant i in the flue gas, $\left(\frac{\text{mg}}{\text{year}}\right)$

$\dot{V}$ – Flue gas volumetric flow rate (FGFR) at STP (Standard Temperature and Pressure), $\left(\frac{\text{Nm}^3}{\text{year}}\right)$

The mass flow rate of the each pollutant was obtained from stoichiometric mass balances and the flue gas volumetric flow rate at ideal condition was calculated assuming that flue gas behaves as ideal gas (Chandra & Chandra, 2004).

The volumetric flow rate of pollutant *i* in the flue gas,

Equation 7

$\dot{V}_i\left(\frac{\text{m}^3}{\text{year}}\right) = \frac{\dot{n}_i R T_1}{P_1}$

Where,

$\dot{n}_i$ – Molar flow rate of Pollutant i, $\left(\frac{\text{mol}}{\text{year}}\right)$

T_1 – Temperature at stack exit

P_1 – Pressure at stack exit

R – Universal gas constant, 8.314 $\frac{\mathrm{J}}{\mathrm{K\,mol}}$

The sum of volumetric flow rate of all the components in flue gas was used to calculate the FGFR using ideal gas Equation of State (EoS).

Equation 8

$$\frac{P_1\dot{V}_1}{T_1} = \frac{P_2\dot{V}_2}{T_2}$$

Equation 9

$$\dot{V}_2 = \frac{P_1\dot{V}_1T_2}{T_1P_2}$$

Where,

$\dot{V}_1$ – Sum of volumetric flow rate $\left(\frac{\mathrm{m}^3}{\mathrm{year}}\right)$ at stack exit conditions

P_2 – 101325 Pa

T_2 – 273.15 K

The mass flow rate of flue gas components estimated from stoichiometric calculations and FGFR calculated from Equation 9 were then inputted to Equation 6 to evaluate the concentration of each pollutant in flue gas at STP. The concentration of the flue gas components like CO_2, H_2O, SO_x, NO_x and PM_{10} were evaluated.

Stoichiometric Calculations

The combustion reactions for solid fuels like coal, coke are as follows.

$$\mathrm{C} + \mathrm{O_2} \rightarrow \mathrm{CO_2}$$

$$\mathrm{H_2} + 1/2\mathrm{O_2} \rightarrow \mathrm{H_2O}$$

$$\mathrm{S} + \mathrm{O_2} \rightarrow \mathrm{SO_2}$$

$$1/2\mathrm{N_2} + \mathrm{O_2} \rightarrow \mathrm{NO_2}$$

$$\mathrm{N_2} + \mathrm{O_2} \rightarrow 2\mathrm{NO}$$

Mass flow rate of i^{th} component in the coal is given by,

Equation 10

$$\dot{M}_i = CFR \text{ x } w/w_i$$

Where,

w/w_i – weight fraction of i^{th} component in the coal

CFR – Coal flow rate (kg/year)

The coal flow rate (kg/year) was calculated using Equation 11.

Equation 11

$CFR = Sp_c \text{ x } GEN.$

Where,

Sp_c – Specific coal consumption (kg/kWh)

GEN – Annual power generation (kWh)

Equation 12

$$Sp_c = \frac{860}{\eta \ x \ GCV}.$$

Where η – percentage of overall efficiency of plant

GCV - gross calorific value of coal (kcal/kg)

Equation 13

$GEN = \text{PLF \% x unit capacity(MW) x PAF \% x 24 x 365}$

Where PLF % - Plant Load Factor (%) = $\frac{\text{Energy generated during the period (kWh)}}{\text{Total Capacity (MW)x Total hours in the period under review}}$

PAF% - Plant Availability Factor, which depends on coal availability

The molar flow rate of component i ($\dot{m}_i$) can be calculated from $\dot{M}_i$ of i^{th} component using molecular mass (MW_i).

Equation 14

$$\dot{M}_i = \frac{\dot{m}_i}{MW_i}.$$

The theoretical amount of oxygen required for complete combustion of coal in combustion chamber was estimated from the molar flow rate for each component.

Equation 15

Theoretical oxygen required for combustion (kmol/year) $O_T = C + \frac{H}{2} + S + N - O.$

Where C, H, S, N, O be the molar flow rate of carbon, hydrogen, sulphur, nitrogen and oxygen in inlet coal, respectively.

Equation 16

Theoretical oxygen required for combustion (kg/year) $o_T = O_T \text{ x } 32.$

Equation 17

Excess oxygen supplied (kg/year) $o_E = (1 + \varepsilon) \text{ x } o_T.$

Where, ε is the percentage of excess air.

Weight percentage of oxygen in air is taken as 23.3%.

Air supplied (kg/year) $A_S = \frac{O_E}{0.233}$.

Equation 18

Weight percentage of nitrogen in air is 76.7%.

Nitrogen in supplied air (kg/year) $N_S = 0.767 \text{ x } A_S$.

Estimation of SO_x, NO_x, PM_{10} and Hg Mass Flow Rates

CO_2 emissions were calculated based on the mass balance approach mentioned earlier using the combustion equations. The percentage conversion of carbon in the boiler was accounted in the calculation. It has been reported in previous experimental studies that about 88–95% of the carbon in coal gets converted at the combustor (Mittal, Sharma, & Singh, 2014). The fraction of carbon that remains un-burnt depends on coal properties, residence time and furnace temperature (Sathyanathan & Mohammed, 2004). From previous experimental results, it was estimated that 0.5–10% of un-burnt carbon mixes with the fly ash and 2–30% is retained in the bottom ash depending on the combustion condition. In the calculation, the conversion of carbon to CO_2 was taken as 95% (Mittal, Sharma, & Singh, 2014). About 4% of carbon in coal was assumed to have been retained in bottom ash and remaining un-burnt carbon was emitted with fly ash.

NO_x formation in the boiler is a complex heterogeneous equilibrium reaction that leads to the formation of NO and other oxides of nitrogen (Cai, Guell, Dugwell, & Kandiyoti, 1993) (Song, Pohl, Beer, & Sarofim, 1982). Instead of using the complex equilibrium equation for mass balance analysis, a simple correlation for nitrogen combustion was developed from previous experimental results. It was observed that the amount of NO formed from these reactions constitutes about 50–95% of the total nitrogen oxides formed. Approximately 5–10% of the nitrogen is being converted to NO_2 (Cai, Guell, Dugwell, & Kandiyoti, 1993). For the simplicity of calculations, it was assumed that only NO was formed in the boiler. From laboratory experiments, it was found that only 15–30% of the nitrogen present in coal is typically converted (Pershing & Wendt, 1977). The unreacted nitrogen mixes with flue gas and is emitted as molecular nitrogen. In the presence of excess air and at high temperature (>1500K), the nitrogen in the inlet air gets oxidised (Bartonova, Juchelkova, Kilka, & Cech, 2011). The nitrogen oxide thus formed is called thermal-NO_x. From experimental analysis, it was found that around 10–25% of the total nitrogen oxides were from atmospheric nitrogen.

Mercury emissions from TPPs were calculated based on the combustion conversion factors mentioned in the peer-reviewed publications. Typically around 58% of the mercury present in the coal was emitted to the air along with other flue gas components. The remaining Hg is in fly ash and can be assumed to be captured by ESPs (CIMFR, 2014).

The percentage of sulphur in coal that gets converted in the combustor was taken as 92.5% (Mittal, Sharma, & Singh, 2014). From laboratory experiments, it was observed that sulphur was retained in ash as calcium sulphate. The compound thus formed was unstable at high temperature and dissociated at boiler temperature, and does not facilitate the retention of sulphur in ash (Mittal, Sharma, & Singh, 2014). On the other hand, a chemical composition analysis of ash collected from various power plants shows significant sulphur content. This can be due to its association with un-burnt carbon. It was also assumed that only SO_2 was emitted from stack since only small fraction of other sulphur oxides were formed in the combustion chamber (Cai, Guell, Dugwell, & Kandiyoti, 1993). The hydrogen in coal gets converted to H_2O completely.

The ash contained in coal splits into bottom ash and fly ash after combustion. Around 25% of total ash in the input coal becomes bottom ash (Jayaranjan, D, van, Ajit, & Annachhatre, 2014). The bottom ash gets collected at coal furnace bottom as it is too large to be carried up along with the flue gas, and remaining fine particles (fly ash) get entrained with other gases. Among all the fly ash fractions, PM_{10} can cause severe respiratory problems, compared to other size fractions. Uncontrolled emission for PM_{10} was estimated by using emission factors established by USEPA for sub-bituminous coal with pulverised coal as firing configuration. Since most of the Indian plants have an ESP, and considering its particulate removal efficiency, the PM_{10} emitted from the stack is taken as 3% of the total PM_{10} released from the combustion chamber. The emission factor for unabated cumulative PM_{10} emission per tonne of coal was calculated using the equation given below (USEPA, 1998).

Equation 19

$$PM_{10}(\text{kg/tonne of coal}) = 2.3 \text{ x } (\text{percentage of ash in coal}) \text{ x } 0.454.$$

Assumptions made for the mass flow rate calculations:

- Steady state process
- Combustion temperature in boiler is 1800 K with 20% excess air (Khan & Khan, 2014) (Mittal, Sharma, & Singh, 2014)
- 92.5% of Sulphur in coal is converted and only SO_2 is formed
- Only 20% fuel Nitrogen is converted to NO. 72.5% of the total NO_X is due to the oxidation of the bound nitrogen in the fuel
- Temperature and Pressure at stack is taken as 422 K , 1atm (Chakraborty, et al., 2008)
- Fuel- lean combustion is considered
- Electro Static Precipitator (ESP) removal efficiency is considered as 97%.

Fuel-lean combustion is normally practiced in TPPs, since fuel-rich combustion leads to CO formation and incomplete combustion of coal. The excess air is given in such a way that the amount of air will not lead to uncontrolled formation of NO_x. It was observed that excess air of 10–30% was given to the combustion in various Indian plants. The molar flow rate of each of the flue gas components were calculated using stochiometric combustion equations, and conversion factors are shown in Table 15.

Table 15: Molar Flow Rate of Flue Gas Components

Flue gas components	Molar flow rate of flue gas components (ṁ) (kmol/year)
CO_2	C x 0.95
H_2O	H
SO_2	S x 0.925
$NO_{fuel\text{-}N}$	(2 x N x 0.20)
NO_{total}	$\frac{(2x\ N\ x\ 0.20)}{0.725}$
O_2	$O_E - O_T + O_R - O_N$
N_2	N_R
Hg	Hg_{coal} x 0.58

Where, $NO_{fuel\text{-}N}$ is the nitric oxide from conversion of fuel nitrogen (kmol/year) and NO_{total} is the total nitric oxide formed (kmol/year).

The oxygen required for thermal-NO_x formation is calculated from the total NO_x formed. Around 27.5% of the NO_{total} was from thermal-NO_x. Using the stoichiometric equation for the formation of NO_x, the oxygen required was calculated using the Equation 20.

Equation 20

$$O_N(\text{kmol/year}) = \frac{0.275}{2} \text{ x } NO_{total.}$$

Oxygen remaining in the boiler due to incomplete combustion is given as,

Equation 21

$$O_R(\text{kmol/year}) = (\text{C x } 0.05) + (\text{N x } 0.8) + (\text{S x } 0.075).$$

Equation 22

Nitrogen remaining in the boiler is given as,

$$N_R(\text{kmol/year}) = \frac{N_s}{28} - \left(\frac{0.275}{2} \text{ x } NO_{total}\right) + (0.8 \text{ x N}).$$

Equation 23

Hg associated with ash is given as,

$$Hg(\text{kmol/year}) = Hg_{coal} \text{ x } (1 - 0.58)$$

The molar flow rate of flue gas components were converted to mass flow rate using molecular mass. The mass flow rate of each flue gas components and volumetric flow rate of flue gas were switched in to calculate the concentration of each component. The estimated current concentration of SO_x, NO_x and PM_{10} are shown in Figure 25, Figure 26 and Figure 27.

The Hg concentration in flue gas is least for NCL (0.0064 mg/Nm^3) and is highest for MCL (0.0238 mg/Nm^3). The average concentration of Hg in flue gas is around 0.012 mg/Nm^3 – lower than stipulated in the emission standards.

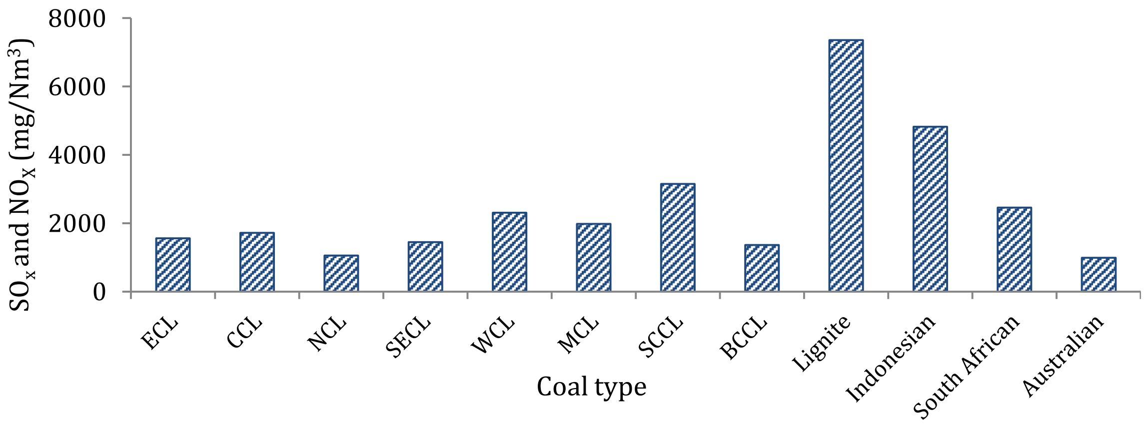

Figure 25: Current Concentration of SO_x in Flue Gas (mg/Nm^3)

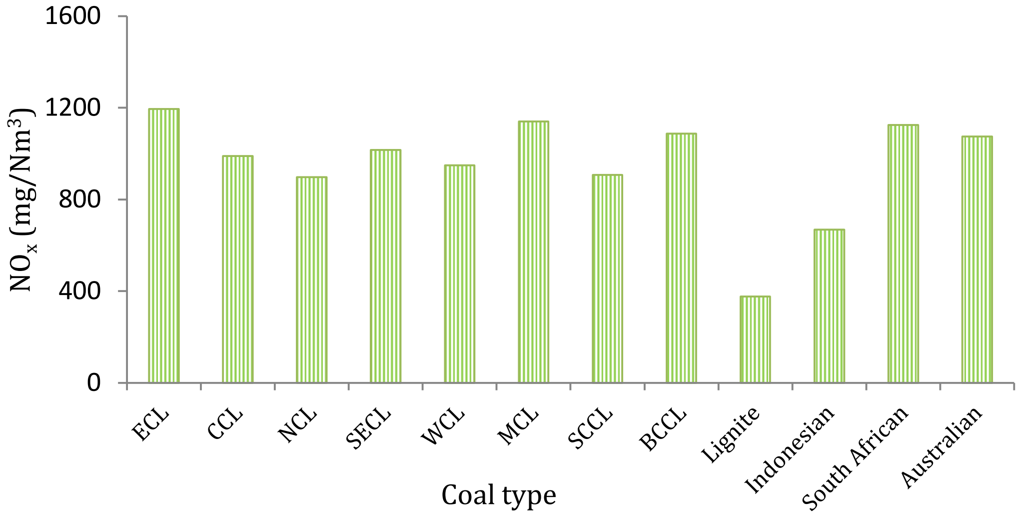

Figure 26: Current Concentration of NO_x in Flue Gas (mg/Nm^3)

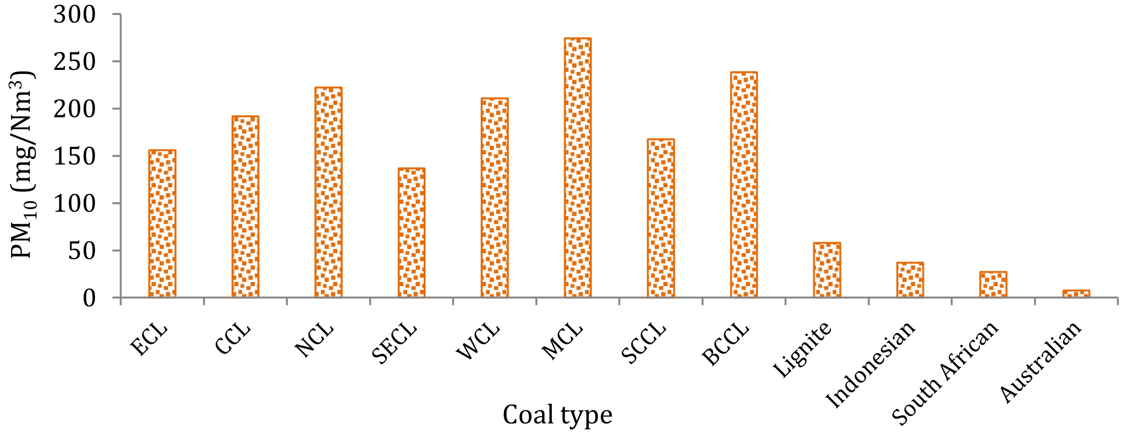

Figure 27: Current Concentration of PM_{10} in Flue Gas (mg/Nm^3)

The mass flow rates of pollutants were also normalised using output or input energy, as described in the main report.

Comparison with Other Data

The present study on current emission factor of pollutant from TPPs was compared with earlier studies. Most of the studies reported emissions in terms of normalised mass flow rates with respect to output electricity (Figure 28). The results from this analysis are in-line with other inventories.

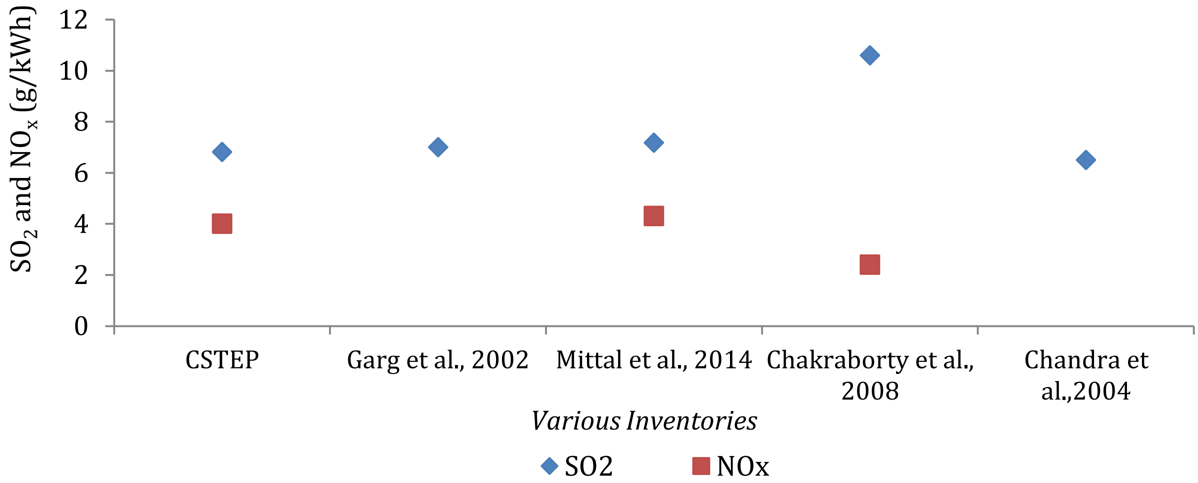

Figure 28: Comparison of Pollutant Emission with Other Inventories

Source: (Garg, Kapshe, Shukla, & Ghosh, 2002; Mittal, Sharma, & Singh, 2014; Chakraborty, et al., 2008; Chandra & Chandra, 2004)

Annexure - C

Pollution Control Technology Compendium

Emissions of SO_x, NO_x and PM can be reduced by implementing PCTs at different stages of a power plant, where it is divided into three stages based on the installation of PCTs.

1. Pre-combustion control technologies
2. In-combustion control technologies
3. Post-combustion control technologies

Working Principle and Applicability of PCTs

1.1. Pre-combustion Control Technologies

Control measures that can be implemented before the boiler are coal beneficiation and blending (Mishra, Das, Biswal, & Reddy, 2015; Cropper, Gamkhar, Malik, Limonov, & Partridge, 2012).

1.1.1. Coal Beneficiation

Coal beneficiation is the process in which coal is washed before pulverisation. This process aims at reducing the ash content of coal. According to a recent study by Cropper et al (2012), washed coal can reduce emissions of PM_{10} by 30% and SO_x by 25%.

1.1.2. Coal Blending

Coal blending involves mixing of low-quality coal with high ash content and low calorific value with other types of coal. This method is employed to increase the thermal energy generation per unit of coal combusted, by increasing the gross calorific value of blended coal. In India, typically blending is done with imported coal with higher calorific value; up to 30% as stipulated by CEA (CEA, 2012 a). Therefore the overall consumption of coal will decrease. As a consequence, ash in per unit coal reduces and is synergetic with the goal to reduce PM per unit electricity generated. However, in some imported types of coal, where sulphur content is higher, this implies a trade-off in terms of higher SO_x emissions per unit electricity generated. For example, a domestic coal (ash content >30% and sulphur content >0.5%) blended with Indonesian coal (ash content < 15%, sulphur content >2%) could result in higher SO_x and lower PM emissions.

1.2. In-combustion Control Technologies

LNB and OFA for NO_x control, and Limestone Injection (LI) for SO_x control, are measures that are installed in a boiler to reduce pollutant emission (Bell & Buckingham, 2010). In-combustion technologies like LNB and OFA are ready retrofits with low installation time requirements (around two months). However fabrication is required for installing a LI set-up.

1.2.1. Low NO_x Burners

LNB is used to reduce NO_x formation in the boiler by reducing combustion temperature and creating oxygen-lean zones. Multiple burners are installed in the combustion chamber which controls the temperature and inlet air. The burners lower the inlet air flow rate thereby reducing the combustion in that boiler zone creating fuel rich zones. Under lower combustion temperatures, due to higher energy requirement for NO_x formation, emissions are limited. LNBs can reduce NO_x emission by 50% and a marginal effect in boiler efficiency occurs (Beér, 2003; Bell & Buckingham, 2010; BHEL, 2016). Major boiler manufacturers in India already include LNBs as part of their new boiler designs (BHEL, 2006).

1.2.2. Over Fire Air

OFAs work on the same principle of reducing combustion temperatures in the boiler to restrict NO_x formation. However, unlike LNBs, in OFAs, the principle of staged air injection above the burner is used. The unique designs of air supply ports in OFAs create fuel rich pyrolysis zones in the lower part of the furnace, supplying only 70–80% of the required air (by stoichiometry), creating a fuel-rich zone. The remaining air that is required is injected into the upper furnace in the form of high velocity air jets. OFAs alone can yield up to 30% NO_x reduction, however in conjunction with LNB, NO_x emissions can be limited by 40–70% (Beér, 2003; General Electric, 2005; ESMAP, 2001).

1.2.3. Limestone Injection

LI into the boiler is one of the cheaper methods to control SO_x emissions. The limestone is either injected above the flame in the boiler, or into the ductwork after the boiler. SO_x present in flue gases bonds with the dry sorbent and forms sulphites, which can be captured in the existing particulate controls. This is an option for plants where land is not available for installing post-combustion control technologies. Requirement of sophisticated design and fabrication are required without which the boiler efficiency could be affected (Bhati & Ramanathan, 2016).

1.3. Post-combustion Control Technologies

FGD for SO_x, SCR/SNCR for NO_x, and ESPs and bag filters for PM are the available post-combustion control technologies.

SO_x control technologies: There are three types of FGD, categorised based on the reagents used or process type (dry, wet and seawater based).

1.3.1. Dry Flue Gas Desulphuriser

Dry FGD covers a range of technologies in which SO_x reacts with limestone particles in a humid environment to form sulphite (Sargent & Lundy, 2007).

Spray Dry Absorber (SDA): The process uses a roof gas disperser, central gas disperser for dispersing flue gas and an atomizer to spray reagent slurry (Babcock & Wilcox Power Generation Group, 2016). Inside a SDA, lime slurry is atomized and sprayed over the flue gas to absorb SO_x. The dry product thus formed is collected in the ESP.

***Novel Integrated Desulphurisation (NID)*:** This GE-Alstom patented control technology consists of an integrated hydrator/mixer system, a duct reactor, and a fabric filter system; each module can service 75 MW. Hydrated lime [$Ca(OH_2)$] is used as a reagent to react with SO_x in humid conditions (GE Alstom, 2016).

Circulating Dry Scrubbers (CDS): In CDS, a fluidised bed of hydrated lime is used for SO_x control. Flue gas is recirculated in this system to facilitate maximum utilisation of unreacted lime (Babcock & Wilcox Power Generation Group, 2016). The products formed are a mixture of calcium sulphite ($CaSO_3$), calcium sulphate ($CaSO_4$) and unreacted lime (CaO). The removal efficiency of CDS can be improved by increasing the amount water sprayed on the fluidised bed (Shahzad & Yousaf, 2017).

Equation 24: Reactions in a CDS:

$$Limestone: CaCO_3\,(s) + SO_2\,(g) \rightarrow CaSO_3\,(s) + CO_2\,(g)$$

$$Lime: Ca(OH)_2\,(s) + SO_2\,(g) \rightarrow CaSO_3\,(s) + H_2O(l)$$

Dry FGDs are more economically feasible for smaller power producing units, since in units of capacity >400 MW, wet FGD installation works out to be less expensive.

1.3.2. Wet FGD

Wet freshwater FGD: The wet freshwater FGD uses lime slurry to remove SO_x. The flue gas drawn from the boiler is directed into the absorption tower by a booster fan. Inside the absorber tower, the flue gas comes into contact with the limestone slurry, sprayed through nozzles installed at the top of the tower. The chemical reaction occurs between the SO_x in the gas and lime slurry, forming calcium sulphite ($CaSO_3$). Calcium sulphite, thus formed, is then oxidised at the bottom of the tower using compressed air, forming calcium sulphate ($CaSO_4$) or gypsum (Babcock & Wilcox Power Generation Group, 2016). Gypsum is a saleable by-product and can be used as a raw material in the cement manufacturing industry. Good quality limestone is required to produce saleable gypsum, and is available in various parts of India (OTM, 2009). The quantity of limestone required per kg of SO_x removed ranges between 1.5 kg and 2 kg, depending on the $CaCO_3$ content in the limestone (Power Engineering, 2006).

Equation 25: Reactions in a Wet FGD:

$$Limestone: CaCO_3\,(s) + SO_2\,(g) \rightarrow CaSO_3\,(s) + CO_2\,(g)$$
$$Lime: Ca(OH)_2\,(s) + SO_2\,(g) \rightarrow CaSO_3\,(s) + H_2O(l)$$
$$CaSO_3\,(s) + ½O_2\,(g) + 2H_2O(l) \rightarrow CaSO_4 \cdot 2H_2O(s)$$

Seawater FGD**:** This process uses seawater as a reagent and no other chemicals are required for the reaction. Instead of limestone, the natural alkalinity of seawater is used to absorb acidic gases like SO_X (Babcock & Wilcox Power Generation Group, 2016). The effluent seawater, after reaction, flows into the seawater treatment system (SWTS) to complete the oxidation of the absorbed SO_x into sulphate. The sulphate ion thus formed is harmless and can be sent back to sea.

The resource linkage data on water source linked to each coal-based power plant were collected. These included 48% authenticated sources data points (data obtained from the Global Energy Observatory, 2015), 36% non-authenticated sources (newspaper articles, industry visit reports and research reports online) and 16% data points based on assumption of 3 km proximity to seawater. Around 82% of the total installed capacity operating during 2015–30 period use fresh water resources.

Table 16: Water Source for Plants Operational in 2015–30 Period

Water Source	Installed Capacity(GW)
Freshwater	217
Seawater	41
Freshwater and Seawater	3
Sewage water	2
Total	263

The water source was used to determine if a power plant can install seawater FGD. This condition was applied across all the power plants, to identify all the coastal power plants that can utilise seawater in their FGDs.

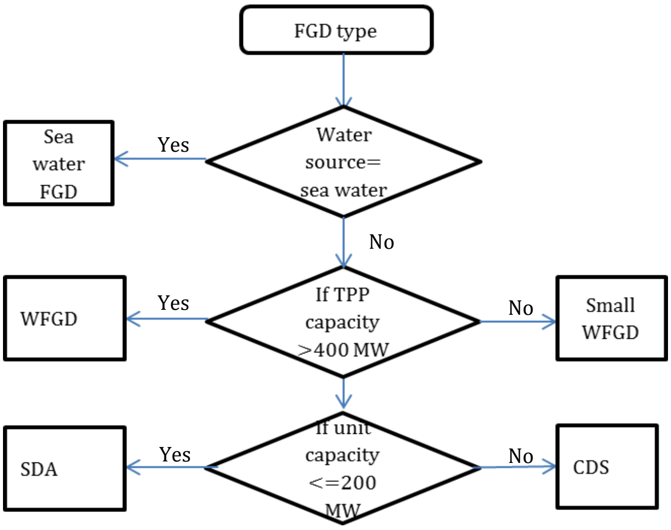

Figure 29: Post-combustion SO_x Control Technology Applicability

1.3.3. SCR

Post-combustion controls reduce NO_X emissions by converting it into nitrogen (N_2) gas. In SCR, the flue gas reacts with ammonia or urea over a catalyst to reduce NO_X into nitrogen and water. Vanadium, titanium and tungsten oxides are used as catalyst (Hatton, 2008). SCRs can reduce NO_x emission by 75–90%.

In SCR, the flue gas along with the reagent is passed over a catalyst bed. Complex reactions occur between NO_x in the flue gas and the reagent. The reaction can be simplified, as given in the equation below.

Equation 26: Ammonia based catalytic reduction system:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$6NO + 8NH_3 \rightarrow 7N_2 + 12H_2O$$

Equation 27: Urea based catalytic reduction system:

$$NH_2CONH_2 + 2\,NO + ½\,O_2 \rightarrow 2\,N_2 + CO_2 + 2\,H_2O$$ [23]

1.3.4. SNCR

SNCR is a non-catalytic system that reacts with an aqueous solution of ammonia water or urea to reduce the NO_x into nitrogen and water vapour (Mussatti, Srivastava, Hemmer, & Strait, 2000). Flue gas temperature should be around 870–1200^{0}C. The ammonia or urea is carried by an air stream or steam, and injected into the flue gas at the appropriate temperature zone. A representation of the applicability is given in Figure 30.

[23] The molar ratio of ammonia fed to NO_x removed is 1 (PCC- Oxidation Technologies, 2017).

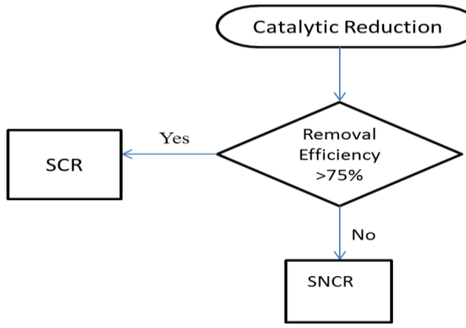

Figure 30: Applicability of Catalytic Reduction Technology

PM Control Technologies

1.3.5. Electrostatic Precipitators (ESP)

An ESP uses electrical forces to capture the charged particles from an incoming gas. In this process, the flue gas is ionised when it is passed between conductors of opposite polarity due to the applied voltage (Environmental Protection Agency, 2016). A high intensity electric field is created, driving the positively charged dust particles towards a ground plate where dust is collected. The dust collected is then transferred to hoppers, referred to as fly ash. For existing plants with ESPs, retrofitting it by replacing the collecting and emitting electrodes, and module additions can improve the dust collection efficiency. A removal efficiency of 97–99.4% can be achieved by ESPs. However, high performance ESPs needed in newer plants would also imply a higher land area requirement due to greater array sizing of filters (CEA, 2007).

Combination of Control Technologies

If a plant does not comply with the target or meet the required removal, despite installing a PCT, then a secondary measures (pre-combustion technology) can be applied. This approach is used for in-combustion techniques for boiler designs in China and USA. With design modifications, to include a combination of measures, there will be a marginal increase in the removal efficiency, which can help a plant attain the emission target. Few combination technologies can be implemented in existing Indian TPPs of recent vintage to meet the targets. These include LNB and OFA; LI and washed coal; and ESP and washed coal (Beér, 2003). The combination of LNB and OFA can reduce 35–60% of NO_x. LI and washed coal can reduce SO_x emission by around 70%. For some of the new plants where emission standards are stringent, installing older ESPs may not be enough to meet the norms. In such cases, usage of washed coal along with the ESP can achieve removal efficiency >99.6%. Detailed descriptions on the PCTs are tabulated in Table 17 (Babcock & Wilcox Power Generation Group, 2016; Bell & Buckingham, 2010; GE Alstom, 2016; Mishra, Das, Biswal, & Reddy, 2015; Bhati & Ramanathan, 2016).

Based on the reviewed literature, we collated the relevant technical parameters and costs of installing and running PCTs. These are summarised in Table 17 and Table 18.

Table 17: Technical Parameters of Pollution Control Technologies

PCT	Removal efficiency (%)	Auxiliary Power Consumption (%)	Fresh water Consumption (m^3/MWh)	Remarks
WFGD	95	0.7%	0.25	Limestone is used as reagent and gypsum is the by-product.
SWFGD	92	1.1%	0	Seawater is used and reagent is not required.
Dry FGD (SDA and CDS)	92-98	0.65- 1%	0.15	Cost effective for unit of capacity <=400 MW. Can reduce SO_3, HCl, HF, heavy metals and $PM_{2.5}$ emission.
LI	57	0.7%	0	Limestone is used as a reagent.
LI+ washed coal	69	0.7%	0	Washed coal is used in the boiler along with LI.
SCR	90	0.6%	0.05	Urea or ammonia are used as reagents with catalyst.
SNCR	57.5	0.6%	0.05	Urea or ammonia are used as reagents.
LNB	50	0%		
LNB+OFA	53	0%		Combining in-process PCT improves removal, efficiency.
ESP	99.6	0.1%		Cost parameters given for high performance ESP retrofits.
ESP + washed coal	99.8	0.1%		Washed coal reduces ash.

Table 18: Cost of PCT

PCT	Capital cost (Million INR/MW)	O&M cost (INR/MW/annum)	Reagent cost (INR/kWh)
WFGD	5	0.6	0.02- 0.15
SWFGD	3	0.6	0
Dry FGD (SDA and CDS)	3.5	0.6	0.02-0.16
LI	1.5	0.6	0.02-0.15
LI+ washed coal	1.5	0.6	0.02-0.16
SCR	3	0.05	0.01-0.07
SNCR	2	0.01	0.01-0.04
LNB	0.5	0	0
LNB+OFA	0.8	0	0
ESP	0.5	0.05	0
ESP + washed coal	1	0.1	0.08

Normalising PCT Costs

The capital cost, O&M cost and reagent costs for each PCT modelled were normalised to per unit of pollutant removed for ease of calculation. The representation of costs of PCT in INR/kg of pollutant removed reflects costs incurred and pollution abated during 2015–30 for each unit. [Refer Table 19].

A representative calculation of normalised costs for a given TPP unit to INR/kg of pollutant removed is given below.

Cost Estimation for WFGD for SO_x Reduction

Capital Cost= INR 5 million/MW

O&M Cost = INR 0.6/MW/annum

Reagent costs = 6 INR/kg of SO_x removed

Type of coal used in TPP – Central Coal fields Limited (CCL)

Assumed PLF = 70% (from CEA database)

Operating years (15 years or remaining plant life during 2015-30, whichever is lesser) = 15 years

Emission factor of SO_x for CCL coal without PCT = 6.1 g/kWh (based on mass balance analysis)

Emission factor of SO_x for CCL coal with FGD = 0.3 g/kWh

SO_x removed = (Emission factor without FGD – emission factor with FGD) = 5.8 g/kWh

Capital costs in INR/kWh= $\frac{\text{Capital cost }(\frac{\text{INR million}}{\text{MW}})}{10^3 \text{ x PLF x 8760 x life of PCT}} = \frac{5 \text{ x } 10^6}{10^3 \text{ x 0.7 x 8760 x 15}} = 0.05$ INR/kWh

Capital costs in INR/kg of SO_x removed = $\frac{\text{Capital costs }\left(\frac{\text{INR}}{\text{kWh}}\right)}{\text{quantity of SOx removed }\left(\frac{\text{kg}}{\text{kWh}}\right)} = \frac{0.05}{5.8*10\text{^}-3} = 8.6\,\frac{\text{INR}}{\text{kg}}$ of SOx removed

O&M costs in INR/kWh = $\frac{\text{O\&M cost }(\frac{\text{INR million}}{\text{MW annum}})}{10^3 \text{ x PLF x 8760}} = \frac{5.8 \text{ x } 10\text{^}5}{10^3 \text{ x PLF x 8760}} = 0.09$ INR/kWh

O&M costs in INR/kg of SO_x removed = $\frac{\text{O\&M cost }(\frac{\text{INR}}{\text{kWh}})}{\text{Quantity of SOx removed}\left(\frac{\text{kg}}{\text{kWh}}\right)} = \frac{0.09}{5.8 \text{ x } 10\text{^}-3} = 15\,\frac{\text{INR}}{\text{kg}}$ of SOx removed

Auxiliary consumption = 0.7% of total generation

Base electricity cost = INR 2/kWh

Energy penalty due to auxiliary consumption = $\frac{Base\ electricity\ cost\ \left(\frac{INR}{kWh}\right)*\%\ of\ auxiliary\ consumption}{Quantity\ of\ SOx\ removed\left(\frac{kg}{kWh}\right)} = \frac{2*0.7*10^{-2}}{5.8\ x\ 10^{-3}}$

= 2.4 INR/kg of SO_x removed

Total INR/kg of SO_x removed during 2015-2030

$$= Capital\ cost\ \left(\frac{INR}{kg}\right) + O\&M\ cost\ \left(\frac{INR}{kg}\right) + Energy\ penalty\ \left(\frac{INR}{kg}\right) + Reagent\ cost\ \left(\frac{INR}{kg}\right)$$

= 32 INR/kg of SO_x removed

In some PCTs which are installed in the boiler, like LI, a reduction in the overall efficiency is likely. This penalty on boiler efficiency was estimated as an additional expense in terms of increase in coal consumption.

Additional expense due to reduction is boiler efficiency in INR/kWh is computed as follows:

$$coal\ cost\ \left(\frac{INR}{MJ}\right) x\ reduction\ in\ efficiency\ of\ boiler(\%)\ x\ overall\ plant\ efficiency\ for\ a\ typical\ plant\ x\ 860\ \left(\frac{kcal}{kwh}\right) x\ 4186\ x\ 10^{-6}$$

$= 0.19\ x\ 0.8\%\ x\ 33\%\ x\ 860\ x\ 4186\ x\ 10^{-6} = 0.002$ INR/kWh

Penalty on efficiency in INR/kg of SO_x removed = $\frac{Penalty\ on\ efficiency\ \left(\frac{INR}{kWh}\right)}{quanity\ of\ SOx\ removed\ \left(\frac{kg}{kWh}\right)} = \frac{0.002}{5.8\ x\ 10^{-3}}$

= 0.34 INR/kg of SO_x removed

The INR/kg of pollutant removed was multiplied by the cumulative pollutant emission abated in each scenario (2015–30). This cost was aggregated under each policy scenario to arrive at the total system cost of installing and operating the PCT for meeting the emission standard.

Table 19: Normalised Pollutant Abatement Costs

PCT	Domestic				Lignite				Indonesian				South African				Australian			
	Capital cost	Reagent cost	O&M cost	Total	Capital cost	Reagent cost	O&M cost	Total	Capital cost	Reagent cost	O&M cost	Total	Capital cost	Reagent cost	O&M cost	Total	Capital cost	Reagent cost	O&M cost	Total
Small WFGD	53	7	15	75	9	3	15	28	18	9	15	42	36	11	15	62	86	10	15	112
WFGD	13	7	15	35	2	3	15	20	3	9	15	28	7	11	15	33	17	10	15	42
CDS	7	7	15	29	1	3	15	20	2	9	15	27	5	11	15	31	11	10	15	37
SDA	7	7	16	30	1	3	16	21	2	9	16	28	5	11	16	32	12	10	16	38
SWFGD	6	0	16	22	1	0	16	17	2	0	16	18	4	0	16	20	10	0	16	26
LI	5	6	14	26	1	3	14	18	2	9	14	25	3	11	14	28	8	10	14	32
LI and washed coal	4	26	20	51	1	6	20	27	1	14	20	36	3	23	20	46	7	42	20	69
SCR	11	12	2	25	22	6	2	30	15	17	2	34	9	20	2	32	10	19	2	31
SNCR	11	13	1	24	23	6	1	29	16	17	1	34	10	20	1	31	10	19	1	29
LNB	3	0	1	4	6	0	1	7	4	0	1	5	3	0	1	3	3	0	1	3
OFA	4	0	1	5	8	0	1	9	6	0	1	7	3	0	1	5	4	0	1	5
LNB+ OFA	5	0	1	7	11	0	1	12	8	0	1	9	5	0	1	6	5	0	1	6
ESP	1	0	0	1	1	0	0	2	2	0	0	3	4	0	0	4	12	0	0	12
ESP + washed coal	1	4	0	5	1	9	0	11	2	18	0	21	3	26	0	30	12	85	0	97

Annexure-D

Monetising Mortality & Estimation of Impact of PCT Costs on Tariff

Table 20: Value of Statistical Life in Literature

Study	Low	High
	In 2015 (INR Crore*)	
Brandon & Hommann, 1994	0.07	0.60
IGIDR, 1994	0.19	4.33
Shah & Nagpal, 1997	0.10	1.7
Simon et al, 1999	2.19	5.14
Shanmugam 2000	4.38	7.83
Shanmugam 2001	16.15	16.45
Madheshwaran, 2007		2.78
*Adjusted from reported values with 8% discount rate based on (Zhuang, Liang, Lin, & Guzman, 2007)		

Source: (Shah & Nagpal, 1997; Simon, Cropper, Alberini, & Arora, 1999; Shanmugam K. R., 2000; Shanmugam K. R., 2001; Brandon & Hommann, 1994; IGIDR, 1994; Madheswaran, 2007)

Research based on empirical data globally suggest that VSL is elastic with income—with increasing average incomes, the average VSL would likely grow in India (Viscusi & Aldy, 2003); this was not accounted for in this analysis.

Tariff Impact

Coal power plants need to implement pollution control measures to achieve the emission target notified by MoEFCC on December 15, 2015. Depending on a unit's installed capacity, vintage and applicability of PCTs, the capital investment for SO_x, NO_x and PM controls, together can range between INR 4–10 million/MW. This indicates that PCTs costs approx. 7–20% of the initial capital investment required for a new plant. Therefore, assessments of impact on tariff with PCT installation in TPPs are required for recovering investment in a justifiable manner.

In the following section, a detailed methodology to evaluate the financial implications of PCT installation, in terms of cost of power generation, is provided. Further, details of policy cases examined to scope out the applicability of possible regulatory provisions are also given.

Figure 31 provides the diagrammatic representation of the approach used for estimating the impact of PCT costs on tariff.

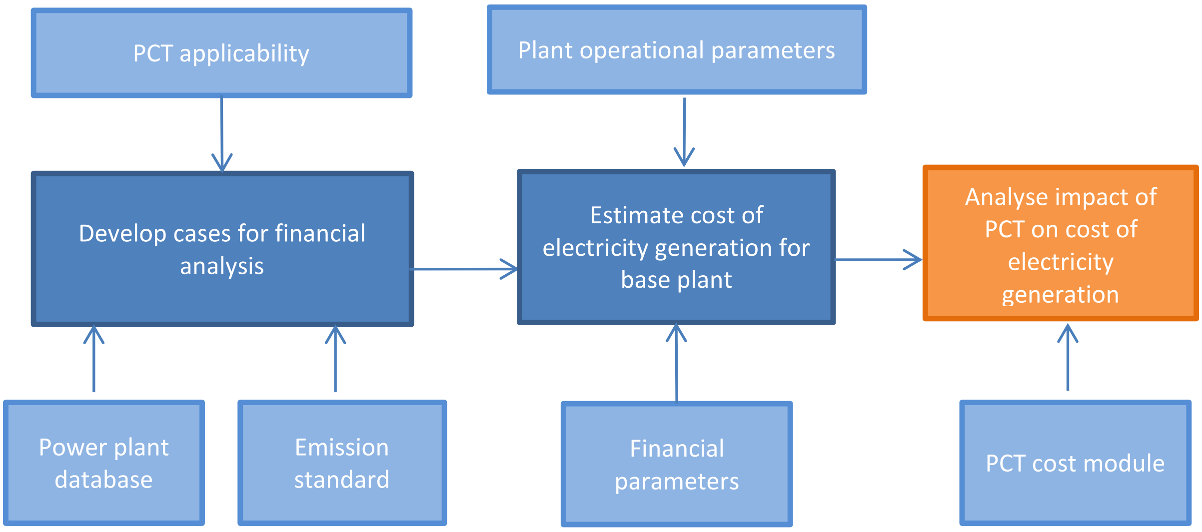

Figure 31: Diagrammatic Representation of Approach for Financial Analysis of PCT Impact on Tariff

1. Case Development for Financial Analysis

The revised emission standards put forth by MoEFCC classified plants based on vintage and unit. The existing and proposed power plant units were classified into the three categories, namely plants commissioned: (1) before 2003; (2) between 2003 and 2016; and (3) after 2016. Further, it is sub-classified based on unit capacity or boiler capacity (lesser than 500 MW and greater than or equal to 500 MW).

As seen in **Error! Reference source not found.**, a majority of the TPP units commissioned efore 2003 were less than 500 MW; larger capacity units have been installed since 2003. Around 72% of the existing installed capacities are of the 2003–16 vintage. In the category for proposed plants (to be commissioned after 2016), nearly 80% of all units in the pipeline are of 600 or 660 MW (Table 3) unit capacity (CEA, 2013) (CEA, 2016 a) (CoalSwarm, 2016). While TPPs installed before 1992 account for around 37 GW (or 135 units), they were omitted from the current financial analysis as they are nearing the end of their life.

Table 21: Number of Units Commissioned in Different Vintage Capacity

Number of units	<1992	1992-2002	2003-2016	>2016
60 MW	19	1	7	2
110 MW	26	1	3	0
210/250 MW	78	62	60	2
550 MW	12	8	59	8
600 MW	0	0	42	14
660 MW	0	0	42	84

Based on the overall efficiency of plant, the boiler type is classified into subcritical (25–34%), supercritical (35–38%) and ultra super critical (39–42%). The plants that were commissioned between 1992 and 2003 comprise of only subcritical ones. Among the plants commissioned between 2003 and 2016, the percentage share of subcritical and supercritical plants are 58% and 42%, respectively. In the proposed plant classification, 86 GW (~ 81% of installed capacity) are supercritical plants, and nearly 5% of them are ultra super critical (CoalSwarm, 2016). The boiler type was also considered as a critical parameter while developing the cases for the financial analysis to estimate PCT installation impact. A representative plant was considered as a case in each vintage category to evaluate the same.

Key assumptions for case development:

- The commissioning year for the case considered for the financial analysis is the year in which maximum units were installed.
- For plants commissioned before 2003, an annual reduction in PLF of 1 % is considered.

Based on the targeted compliance, we evaluated the control measures needed to be implemented in each case. For Case 1, PCTs with lesser removal efficiencies and comparatively lower capital cost are suitable to meet the relatively lenient emission standards notified for this category of plants by MoEFCC. Therefore, a combination of pre-combustion and in-combustion control technologies [refer Annexure-C] were considered for this category. The usage of washed coal, instead of raw coal, can reduce SO_x emissions in flue gas by 25% and particulate matter emissions by 30%. The washed coal can also improve the plant's performance by enhancing overall plant efficiency by 1.2% and increasing PLF by 4%. It can also improve the existing ESP efficiency, thus ruling out the need for upgradation of older ESPs to meet new standards. In-combustion technologies such as OFA and LNB for NO_x, and LI for SO_x were considered to meet the prescribed standards.

The Case 2a category with lower capacity units have to comply with slightly stringent standards of NO_x and PM reduction. High performance PCTs such as SCR for NO_x and ESPs/ Bag filters for PM reduction are also needed for this category to meet the standards. Since most of the TPP units in this category do not have the land required for FGD installation, these plants can opt for a LI system for SO_x control, given its lax standards.

For Case 2b plant units, PCTs with higher performance and removal efficiencies are needed as the emission standards are more stringent. Post-combustion control technologies such as FGD for SO_X reduction can be deployed in these plants as they have enough land area, in accordance with the MoEFCC guidelines on environmental clearance for larger capacity units (CEA, 2010).

For plants commissioned after 2016, emission standards are even more stringent, and they will be required to install efficient post-combustion control technologies to adhere to the standards. The control measures chosen for each case are given in Table 22.

Table 22: Cases for Financial Analysis

Case	Pollution control technologies implemented
Case 1	LNB and OFA, Use washed coal, LI
Case 2a	Up gradation of ESP, LI, SCR
Case 2b	Up gradation of ESP, FGD, SCR
Case 3	ESP, FGD, SCR

2. Implications on Emissions with the Implementation of PCTs

Based on the case-wise controls identified in the previous section, it is imperative to check whether emission standards are met. In order to evaluate this, the cumulative reduction from the pollution control measures was estimated using a basic mass balance approach [Refer Annexure-B] for a representative coal power plant using a 50:50 blended coal from South

Eastern Coal Field Limited (SECL) and Mahanadi Coal Field Limited (MCL)[24]. The implications on emissions for each case were compared with the applicable emission standards, and are presented in Table 23.

Table 23: Implications on Emissions with the Implementation of PCTs

Cases		Emission factor (mg/Nm³)			Emission factor[25] (g/kWh)		
		SO_x	NO_x	PM_{10}	SO_x	NO_x	PM_{10}
Case 1	Unabated Emission	1670	871	6489	5.92	3.09	22.99
	With PCTs	564	413.75	45.44	2.00	1.47	0.16
	Target for compliance	600	600	100	2.13	2.13	0.35
Case 2a	Unabated Emission	1670	871	6489	5.58	2.91	21.69
	With PCTs	565	87.18	38.97	1.88	0.29	0.13
	Target for compliance	600	300	50	2.00	1.00	0.17
Case 2b	Unabated Emission	1670	871	6489	5.42	2.82	21.04
	With PCTs	83.63	87.18	38.97	0.27	0.28	0.13
	Target for Compliance	200	300	50	0.65	0.97	0.16
Case 3	Unabated Emission	1670	871	6489	5.08	2.60	19.72
	With PCTs	83.62	87.18	25.99	0.25	0.30	0.08
	Target for Compliance	100	100	30	0.30	0.30	0.09

3. Methodology for Tariff Calculation for Coal TPPs

The impact of PCTs on tariff was determined based on CERC's guidelines for tariff determination. The CERC has so far set forth three regulatory orders for tariff determination for central utilities for the periods 2004–09, 2009–14 and 2014–19, as per the Electricity Act 2003 (CERC, 2004) (CERC, 2009 b) (CERC, 2014). Although only 29% of the total coal/lignite power plants are centrally owned, in the current analysis, CERC's guidelines have been followed for tariff determination (CEA, 2016 a) (CoalSwarm, 2016). The guidelines provided by CERC serve as the guiding principle for SERCs as well.

Tariff is calculated by dividing the expenditure into two components: fixed cost; and variable cost. The fixed cost comprises of Return on Equity (profit), Depreciation, Operation and Maintenance expenses, Interest on capital investment, and interest on working capital. The variable cost includes coal cost, secondary fuel/oil cost, water charges, and PCT reagent cost. Financial and operating parameters required for the calculations have been taken from CERC's guidelines and actual plant data.

For each case considered for the financial analysis, CERC's guidelines that prevailed in their respective commissioning year were used to derive the operational and financial parameters (CERC, 2009 b) (CERC, 2014). Due to the lack of proper guidelines before 2004, CERC's guidelines for 2004–09 were used to develop the parameters (CERC, 2004) for Case 1 plants. The base year for the tariff determination is taken as 2018, with the useful plant life as 25 years.

The cost for generation of electricity is given as,

[24] SECL and MCL supplies around 50% of the coal required by coal power plants (MoC, 2016)
[25] Target for compliance in terms of g/kWh is calculated by multiplying concentration based emission standards with the electricity generated in each case

$$Cost\ for\ generation\ of\ electricity\ \left(\frac{INR}{kWh}\right) = \frac{Total\ expenditure\ \left(\frac{Rs}{year}\right)}{Net\ generation\ \left(\frac{kWh}{year}\right)}$$

The total expenditure incurred by the plant is divided into two parts, fixed cost and variable cost. The fixed part includes:

1. Interest on capital loan
2. Return on equity capital
3. Interest on working capital
4. Depreciation
5. Operation and maintenance (O&M) cost

The variable part of tariff depends on the landed[26] cost of:

1. Coal
2. Secondary fuel oil
3. Water

3.1 Components of fixed cost

Return on Equity

Return on Equity (RoE) is a measure of profitability that determines the profit a company generates with the money invested by the shareholders. The base rate of RoE for each case is taken as the base rate prescribed by CERC guidelines.

Table 24: Base Rate for Return on Equity as per CERC guidelines

Financial parameters	2004-09 guidelines	2009-14 guidelines	2014-19 guidelines
Return on Equity %	14%	15.50%	15.50%

Interest Rate for Capital Loan

The capital investment for a coal power plant includes benchmark capital cost (equipment cost), land cost, construction expenditure, Interest during construction (IDC), and Incidental expenditure during construction (IEDC).

The capital investment for each representative case were derived from CERC reports and Detailed Project Reports (DPRs) of the coal power plants (CERC, 2012) (Maharastra Electricity Regulatory Commission , 2010). IDC is calculated by assuming 12.5% as the interest rate, considering the base plant construction time defined by CERC (~31–36 months), and validating the same using the DPRs of new plants[27] (CERC, 2014) (STEAG Energy Services India Pvt. Ltd, 2014). IEDC is considered as 2% of the bench mark cost.

Land required for a base plant is around 0.99 acres/MW and for WFGD it is 0.007 acres/MW (Samantaray, Singh, & Mukherjee, 2004). The land cost is taken as INR 7 lakhs/acre; in other words INR 0.69 million/MW (EAI, 2013).

[26] Landed cost includes transportation cost and taxes
[27] IDC for new coal power plants is around 8–19% of total capital investment.

The debt equity ratio of capital investment is taken as 70:30, as per CERC guidelines. Based on CERC's guidelines, the actual plant data were considered for loan interest rate (12.5%) (CLP India Private Limited, 2015) (CERC, 2013). The moratorium period is not considered in our analysis, therefore power plants have to pay interest on the term loan from the commercial date of operation (CERC, 2004).

The total capital cost for base plant cases are calculated as,

Equation 28

$$Total\ Capital\ Investment = Bench\ mark\ capital\ cost + IDC + IEDC$$

Table 25: Total Capital Investment for Representative Cases

Cases	Unit capacity	Bench mark capital cost (INR million/MW)	IDC (INR million/MW)	IEDC (INR million/MW)	Total capital investment (INR million/MW)
Case 1	210 MW	35	5.7	0.7	42.1
Case 2a	210 MW	40	6.5	0.8	47.9
Case 2b	500 MW	40	6.5	0.8	47.9
Case 3	660 MW	50	8.0	1	59.7

Interest on Working Capital

The interest rate for working capital loan is taken as 13.2% for all the cases based on the DPRs of the TPPs and CERC's tariff orders (CLP India Private Limited, 2015) (CERC, 2013) (STEAG Energy Services India Pvt. Ltd, 2014). The working capital for TPPs includes the following components:

Table 26: Components of Working Capital

Working capital components	2004–09 guidelines	2009–14 guidelines	2014–19 guidelines
Coal stock	1 ½ moths for pit-head 2 months for non-pit head	1 ½ months for pit-head 2 months for non-pit head	1 ½ months for pit-head 2 months for non-pit head
Secondary fuel oil stock	2 months	2 months	2 months
Maintenance spares	1% of historical capital cost escalated @ 6% per annum	20% of O&M	20% of O&M
Sales Receivables	2 months	2 months	2 months
O&M expenses	1 month	1 month	1 month

Operation and Maintenance (O&M) Cost

The O&M cost for a TPP includes expenditure on repairs and maintenance, wages, insurance, etc., but excludes fuel cost and water charges. The base plant O&M cost for various plant capacities were given in CERC's guidelines.

Table 27: Operational and Maintenance Expenses

	Unit capacity	Unit	2004–09 guidelines	2009–14 guidelines	2014–19 guidelines
O&M expenses	210/250 MW	lakhs/MW	10.4	18.2	28.7
	500 MW	lakhs/MW	9.36	13	23.9
	600 MW and above	lakhs/MW	9.36	11.7	17.3
Escalation rate of O&M expenses		%	4%	5.72%	6.30%

Depreciation

Depreciation was calculated on 90% of the total capital investment, using the Straight Line Method for the first 12 years, with the depreciation rate prescribed by CERC. The remaining depreciable amount is distributed across the remaining plant life. For simplicity in calculation, the depreciation rate for equipment is considered as overall depreciation rate, as it contributes to around 80% of the total investment. The depreciation rate for tariff calculation is as per CERC guidelines.

Salvage Value

The salvage value for coal power plants after 25 years is considered as 10% of the benchmark capital cost (excluding construction and erection expense).

Table 28: Depreciation Rate as per CERC guidelines

Depreciation (for 12 years)	**Unit**	**2004–09 guidelines**	**2009–14 guidelines**	**2014–19 guidelines**
	%	5.28%	5.83%	5.28%

Term Loan Period

The term loan period is calculated by equating the principle repayment in each year to the depreciation amount, as per the CERC guidelines.

Net Electricity Generation

The net electricity generation is determined based on the operational norms specified by CERC. The operational norms for coal power plants, as per CERC guidelines, are given in Table 29.

Table 29: Operational Norms for Coal Power Plant

Operational parameters		**Unit**	**2004–09 guidelines**	**2009–14 guidelines**	**2014–19 guidelines**
Plant Availability Factor (PAF)		%	80%	85%	85%
Plant Load Factor (PLF)		%	80%	85%	85%
Gross Station Heat Rate	210/250 MW	kCal/kWh	2650	2500	2450
	500 MW		2550	2425	2375
	New Plants		N/A	N/A	1.045 x Design Heat Rate[28]
Auxiliary Power Consumption (APC %)	210/250 MW	%	9%/8.5%[29]	9%/8.5%	9%/8.5%
	500 MW (steam driven)		7.5%/7%	6.5%/6%	5.75%/5.25%
	500 MW (power driven)		9%/8.5%	9%/8.5%	7.75%/8.25%

The gross electricity generated by a coal power plant is given as,

Equation 29

$$Gross\ \ Generation\ \left(\frac{kWh}{year}\right) = PAF(\%)x\ PLF(\%)x\ unit\ capacity\ (MW)x\ 24\ x\ 365\ x\ 1000$$

Where, PAF – Plant Availability Factor

[28] Maximum Design Heat rate is 2273 kcal/kWh for plants with sub-bituminous Indian coal as fuel (CERC, 2014)
[29] The higher value of auxiliary consumption in each category denotes the plants with cooling tower

PLF- Plant Load Factor

Equation 30

$$Net\ Electricity\ generation\ (\frac{kWh}{year})\ =\ (1 - APC)\ x\ Gross\ generation$$

Therefore Fixed Cost for Electricity Generation is,

Equation 31

$$\text{Fixed cost per unit}\ \left(\frac{\text{Rs}}{\text{kWh}}\right) = \frac{Return\ on\ Equity + Interest\ on\ term\ loan + Interest\ on\ working\ capital + OM\ expenses + Depreciation - Salvage\ value}{Net\ Electricity\ Generation}$$

3.2 Components of Variable cost

The variable cost component to estimate the LCOE is calculated 2017 onwards, unlike the fixed cost component, which was calculated from the commercial operation year of the plant.

Coal

The sub-bituminous Indian coal is considered as the coal type for all the representative cases. A fuel mix of SECL and MCL in the ratio 50:50 is considered as the coal type [Refer Annexure-B] (MoC, 2016) (CIMFR, 2014). The landed coal cost is calculated by adding a coal cess amount of INR 400/tonne of coal and INR 768/tonne (transportation cost for 500 km) as the transportation cost, as per the railway freight charges (Ministry of Railways, 2015) (Chandrasekaran, 2016) (CIL, 2016). The coat cost, as on May 2016 for SECL, MCL 50:50 blended coal, is INR 2238/tonne. The composition of coal is given in Table 30.

Table 30: Coal Composition

Component	Weight/Weight Ratio
Carbon	0.429
Hydrogen	0.028
Sulphur	0.005
Nitrogen	0.01
Oxygen	0.078
Moisture	0.072
Ash	0.345
Hg	1.50E-07

The GCV of coal is 4289 kcal/kg. The escalation rate for coal is not considered in the present analysis as per the CERC notification on coal procurement rate for power sector (CERC, 2016).

Secondary Fuel Oil

The cost of secondary fuel oil is taken from literature, and is around INR 10,000/kl. Its GCV is considered as 10,000 kcal/litre (CERC, 2009 a). 0% escalation rate is assumed for secondary fuel oil.

Water Charges

The representative plants considered as base cases are inland plants. They mostly depend on fresh water sources. The cost of water for coal power plants is taken as INR 7 per m^3 and the specific consumption 7 m^3/MWh (CEA, 2012 b) (Muthuraman, 2016).

Specific oil consumption = 1 ml/kWh (CERC, 2009 a)

Equation 32

$$Specific\ oil\ cost\ (INR/kWh) = Specific\ oil\ consumption\left(\frac{ml}{kwh}\right)\ x\ Cost\ of\ oil\ \left(\frac{INR}{kl}\right) x\ 1000$$

Equation 33

$$Specific\ coal\ cost\ (INR/kWh) = Specific\ coal\ consumption\left(\frac{kg}{kwh}\right)\ x\ Cost\ of\ coal\ \left(\frac{INR}{tonne}\right)\ x\ 1000$$

Equation 34

$$Specific\ water\ charge\ (INR/kWh) = Specific\ water\ consumption\left(\frac{m^3}{Mwh}\right)\ x\ Water\ \left(\frac{INR}{m^3}\right)\ x\ 1000$$

Equation 35

$$Total\ variable\ cost\ per\ unit\ of\ electricity\ generated = Specific\ oil\ cost + Specific\ coal\ cost + Specific\ water\ charge$$

Equation 36

$$Variable\ cost\ component\ per\ unit\ (INR/KWh) = \frac{Total\ variable\ cost\ per\ unit\ of\ electricity\ generated}{Net\ Electricity\ Generation}$$

3.3 Levelised Tariff of Electricity (LToE)

The discounted rate is required to calculate LToE. The Weighted Average Cost of Capital (WACC) is considered as the discount rate for tariff calculation. WACC is calculated as follows:

Equation 37

$$WACC = \frac{(Equity\%\ x\ RoE\ ) + (Debt\%\ x\ Interest\ rate\ for\ capital\ investment)}{Equity\% + Debt\%}$$

The discounted rate for each representative case was calculated considering the CERC's guidelines prevalent in each time period.

Table 31: Discount Rate

Financial parameters	Unit	2004-09 guidelines	2009-14 guidelines	2014-19 guidelines
Discount rate (WACC)	%	12.95%	13.40%	13.40%

The LToE has been calculated for the remaining plant life using the following equation:

Equation 38

$$Levelised\ Tariff\ of\ Electricity\ (LToE) = \frac{\sum_{i=2017-CoD\ of\ Plant}^{25}(Fixed\ cost + Variable\ cost) * Discount\ rate_i}{\sum_{i=2017-CoD\ of\ Plant}^{25} Discount\ rate_i}$$

4. Tariff Determination for Coal Power Plants with PCTs

The tariff determination with PCTs was conducted following the same methodology as the one described above.

The additional costs that the plant has to incur for the installation of PCT are mentioned below.

Fixed cost: Capital cost for PCT installation

Variable cost:

1. Reagent costs for PCTs
    a. Limestone for FGD
    b. Urea/ammonia for SCR/SNCR
2. Catalyst cost for SCR
3. Additional Water charges for PCTs
4. Costs for waste disposal of gypsum slurry

4.1 Fixed Cost for PCTs

Capital Investment for PCTs

The capital investment for PCTs varies depending on the PCTs chosen. The PCTs considered for each case, with the capital investment needed, are shown in Table 32.

Table 32: Capital Investment for PCTs Implemented in each Representative Plant

Cases	Capital investment (INR million/MW)
Case 1	3.9
Case 2a	6
Case 2b	8
Case 3	8.5

The cost of washed coal is approximately INR 490/tonne (Cropper, Gamkhar, Malik, Limonov, & Partridge, 2012).

The capital investment of PCTs for Case 1, 2a, 2b is considered as an additional fixed cost, as per the CERC guidelines. For new plants, the capital investments for PCTs are included in the base plant capital investment with a debt equity ratio of 70:30.

Interest on Working Capital for PCTs

The use of reagents in post-combustion technologies demands an additional working capital. The added components to the working capital are:

- Limestone cost for 2 months of generation
- Urea cost for 2 months of generation

- O&M expenses of FGD, SCR, ESP

Table 33: Cost of Reagents and By-product

Reagent	Cost (INR/tonne)
Low quality limestone (70% pure)	2900
Urea	12000
High quality limestone[30]	3500
Gypsum (by-product from FGD)	1200

O&M Expenses for PCTs

Table 34: O&M Expenses for PCTs

	PCTs	INR million/MW
O&M cost	WFGD	0.6
	SCR	0.5
	ESP	0.5
	SNCR	0.1
	LNB & OFA	0
	Limestone Injection	0

Depreciation Rate for PCTs

Depreciation is calculated using the Straight Line Method (SLM), assuming the depreciation rate as that of the base plant.

Salvage Value for PCTs

The salvage value of 5%[31] is assumed after the end of base plant life.

Net Generation of Electricity

Equation 39

$$Net\ electricity\ generation\ (\frac{kWh}{year}) = (1 - APC - APC\ of\ PCTs)\ x\ Gross\ electricity\ generation$$

Fixed Cost for PCTs for Case1, 2 Plants

Equation 40

$$\text{Fixed cost per unit for PCTs} \left(\frac{\text{INR}}{\text{kWh}}\right) = \frac{PCT\ allowance + Interest\ on\ working\ capital\ for\ PCTs + OM\ expenses + Depreciation - Salvage\ value)}{Net\ electricity\ generation}$$

Fixed Cost for PCTs for Case 3 Plants

[30] Limestone of high quality is required to generate saleable by-product.
[31] 5% salvage value is assumed, as PCTs consist of lesser amount of metal parts, as compared to base plant

Equation 41

$$\text{Fixed cost per unit for PCTs}\left(\frac{\text{INR}}{\text{kWh}}\right) = \frac{\begin{array}{c} interest\ on\ PCT\ investment + Interest\ on\ working\ capital\ for\ PCTs + OM\ expenses + \\ Depreciation - Salvage\ value) \end{array}}{Net\ electricity\ generation}$$

Total Fixed Cost for Coal Power Plants with PCTs

Equation 42

$$\text{Fixed cost for coal power plants with PCTs}\left(\frac{\text{INR}}{\text{kWh}}\right) = Fixed\ cost\ for\ base\ plant\ + Fixed\ cost\ for\ PCTs$$

4.2 Variable Cost for PCTs

The reagents, such as limestone and urea, requirement for the representative cases were calculated based on a mass balance analysis.

Approximately 1.5 tonne of limestone is required to remove one tonne of SO_x (Buecker, 2010; Bhati & Ramanathan, 2016). The limestone required per year is calculated from the annual SO_x generation [Refer Annexure-B].

Equation 43

$$Variable\ cost\ for\ limestone\ (INR/kWh)\ = \frac{Limestone\ required\ in\ an\ year * Cost\ of\ limestone}{Net\ electricity\ generation}$$

In SCR/SNCR, urea requirement per tonne of NO_x removal is around 0.625 tonne (Process Combustion Corporation, 2016; Bhati & Ramanathan, Clearing the Air, 2016). The annual urea requirement is calculated from NO_x emission, and the variable cost for urea is calculated.

Equation 44

$$Variable\ cost\ for\ urea\ (INR/kWh)\ = \frac{Urea\ required\ in\ an\ year * Cost\ of\ urea}{Net\ electricity\ generation}$$

Equation 45

$$Variable\ cost\ for\ water\ \left(\frac{INR}{kWh}\right) = \frac{(Water\ required\ for\ FGD + SCR)\left(\frac{m^3}{MWh}\right) * Cost\ of\ water\ \left(\frac{INR}{m^3}\right) * 10^{-3}}{Net\ electricity\ generation\ \left(\frac{kWh}{year}\right)}$$

Miscellaneous Expenses

The other variable costs with PCT implementation are given in Table 35 .

Table 35: Miscellaneous Expenses

	INR/kWh
Waste disposal for FGD (for low quality limestone)	0.092
Catalysts cost for SCR	0.024

Equation 46

$$\text{Variable cost of PCTs}\left(\frac{\text{INR}}{\text{kWh}}\right) = Variable\ cost\ for\ limestone\left(\frac{\text{INR}}{kWh}\right) + Variable\ cost\ for\ Urea\left(\frac{\text{INR}}{kWh}\right) + Variable\ cost\ for\ water\left(\frac{\text{INR}}{kWh}\right) + Miscellaneous\ expenses\left(\frac{\text{INR}}{kWh}\right)$$

4.3 Levelised Tariff of Electricity (LToE)

Equation 47

$$Levelised\ Tariff\ of\ Electricity\ (LToE) = \frac{\sum_{i=\ 2017-CoD\ of\ Plant}^{25}(Fixed\ cost + Variable\ cost + fixed\ cost\ of\ PCTs + variable\ cost\ of\ PCTs) * Discount\ rate_i}{\sum_{i=\ 2017-CoD\ of\ Plant}^{25} Discount\ rate_i}$$

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