ABSTRACT

Title of Document: ESSAYS ON ENERGY AND ENVIRONMENT IN INDIA

Kabir Malik, Doctor of Philosophy, 2013

Dissertation Directed By: Professor Maureen Cropper
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Expanding electricity generation is driving economic activity in the developing world. Increasing energy demand, largely met through the combustion of coal and natural gas, poses significant trade-offs between development objectives and environmental well-being. In this dissertation I examine the Indian electricity sector.

Chapter 1 studies the impact of regulatory changes affecting state-owned electricity utilities on the efficiency of coal-fired power plants. The results indicate that the unbundling of generation companies from state-owned utilities improved operating reliability at coal-fired power plants. The improvements were, however, restricted to states that restructured their electricity utilities prior to the Electricity Act of 2003. The results also show that the reforms did not result in an improvement in thermal efficiency or capital utilization at these plants.

Chapter 2 estimates the health impacts from PM2.5, SO_2 and NO_x emissions from coal-fired plants in India. I derive estimates of the total premature mortality impact from

each plant in my sample associated with each of the three pollutants. I find that the majority of the impact, about 70%, is due to SO_2 emissions—a pollutant currently unregulated in India due to the low sulfur content of Indian coal. I also conduct a cost benefit analysis of two pollution control options currently available in India—coal washing and the installation of an flue-gas desulfurization unit (FGD). The results from the case study show that both options pass the cost-benefit test using reasonable estimates of the Value of a Statistical Life (VSL) for India.

Chapter 3 more thoroughly examines the benefits and costs of FGD retrofit at coal-fired power plants in India. Using emissions estimates and output from a medium-range Lagrangian puff (atmospheric) model I estimate the net benefits of FGD installation for a sample of power plants. The results show that a substantial proportion of power plants pass the cost-benefit test for an FGD installation using reasonable estimates of the VSL for India. The results indicate a substantial scope for FGD installation to control SO_2 emissions in the Indian power sector and suggest that it should be considered as a viable option for pollution control policy.

ESSAYS ON ENERGY AND ENVIRONMENT IN DEVELOPING COUNTRIES

By

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Dissertation submitted to the Faculty of the Graduate School of the
University of Maryland, College Park, in partial fulfillment
of the requirements for the degree of
Doctor of Philosophy
2013

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Foreword

Chapter 1 and 2 of this dissertation includes coauthored work. I am the lead author of the work in Chapter 1 and an equal coauthor on Chapter 2. I have made substantial contribution to work in both chapters and have complied with all University of Maryland guidelines for including jointly authored research as part of my dissertation.

Dedication

To my parents.

Acknowledgements

First and foremost, I would like to thank Maureen Cropper, the chair of my dissertation committee, for her support. I would not have managed to go through this process without her guidance and encouragement. Despite her busy schedule, she always took the time to listen and comment on my ideas and work. I could not hope for a better mentor. I have learned a lot from working closely with her and hope to continue to do so in the future. I also thank my dissertation committee, Anna Alberini, Rob Williams, Charles Towe and Russell Dickerson for their comments and helpful suggestions.

I am especially grateful to my collaborators Alex Limonov, Ian Patridge, Shama Gamkhar and Sarath Guttikunda. This work has benefited greatly from their help and contributions. I thank Mike Toman for taking a keen interest in this research and for providing crucial funding that significantly increased the quality of this work. I also gratefully acknowledge the financial support of the Anne G. Wylie dissertation fellowship, which provided me funding during the last year of my graduate studies.

My ideas and abilities were shaped by my experience at AREC. Especially classes taught by Professors Richard Just, Anna Alberini, Maureen Cropper and Ramon Lopez influenced my thinking and interests a great deal. I also thank the departmental staff, especially Pin Wuan Lin, for making many tasks so much easier.

My time at AREC was made special by my classmates and friends. I thank my classmates: Amparo, Fanqing, Magda, Adan, Denny, Jeff, Jorge, Tim, Upu, Seth, Will and Andrew for being the great companions for both work and play. Special thanks to Kanishk, Trang, Anand, Sushant, Shu Lin, and Ariel for being part of my Silver Spring family and for the many long nights of wandering discussions fueled by IPAs and affogatos.

Finally, I thank Josefina. Her presence throughout these years has been a source of great strength and support. Her kindness and patience helped me get through the toughest of times.

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I. Chapter 1

The Impact of Electricity Sector Restructuring on Coal-fired Power Plants in India[1,2]

1. Introduction

During the past 30 years, over two dozen countries, including the US, have attempted to reform their electricity sectors. Vertically integrated monopolies have been broken into companies that generate electricity and those that distribute it, in an attempt to attract independent power producers into the industry and promote competition. Cost-of-service regulation has been replaced by incentive-based regulation and, in some cases, by competitive wholesale power markets. The ultimate goal of these reforms is to improve both technical and allocative efficiency in electricity generation and to pass these savings onto consumers.

This paper examines the impact of electricity sector restructuring on the operating efficiency of thermal power plants in India. Between 1996 and 2009, 85 percent of the coal-based generation capacity owned by state governments was unbundled from vertically-integrated State Electricity Boards (SEBs) into newly created state generation companies. The restructuring sought to expand generation capacity and reduce costs by

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[1] This is based on work jointly authored with Maureen Cropper, Alexander Limonov and Anoop Singh. I am the lead author of the work presented here.

[2] Acknowledgements: This research was supported by grants from the World Bank and Resources for the Future.

encouraging the entry of independent power producers and by “corporatizing” unbundled generation companies. Although government owned, these companies were granted formal autonomy in technical, financial and managerial decisions. I examine whether greater managerial discretion and specialization in generation increased operating reliability and thermal efficiency at unbundled power plants.

A growing literature has documented the impacts of restructuring on the performance of power plants in the United States.[3] Fabrizio et al. (2007) find that, in the short term, the restructuring did not improve technical efficiency at thermal power plants, but did reduce expenditure per kWh on non-fuel inputs. Knittel (2002) suggests that power plants facing compensation schemes with performance incentives were more efficient than plants compensated on a traditional cost-plus basis. Davis and Wolfram (2012) find that the selling of nuclear reactors to independent power producers led to a decrease in forced outages at nuclear power plants and a corresponding increase in electricity production.

To investigate the impact of reforms in the Indian electricity sector I construct a panel data set of coal-based electricity generating units (EGUs) for the years 1988–2009. The variation in the timing of reforms across states allows me to estimate the impact of unbundling on EGU reliability and plant thermal efficiency. My difference-in-difference specification assumes that conditional on control variables—EGU/plant characteristics, EGU and year fixed effects, and state-specific linear time trends—the assignment of the

[1]A related empirical literature evaluates the impact of reforms on plant dispatch order (Douglas 2006) and competitive behavior in wholesale power markets (Borentstein, Bushnell,and Wolak 2002; and Hortacsu, and Puller 2011).

timing of reforms (including not to reform) is exogenous. Under this assumption, these models identify the effect of reforms from a comparison of the performance of plants in states that unbundled with plants in states that had not yet unbundled.

To eliminate the possibility of state-year shocks affecting my estimates of average treatment effects, I also present results from a triple-difference specification that uses EGUs operated by central government owned generation companies as an additional control group. These companies operate outside the purview of state governments and thus were not directly affected by the reorganization of the SEBs.

My results suggest that the gains from unbundling of generation from transmission and distribution were limited to the states that reformed before the Electricity Act of 2003. In these states, on average, EGUs at state-owned plants experienced a 5 percentage point reduction in forced outages as result of unbundling—roughly a 25 percent reduction compared to the 1995 average. The decrease in forced outages was accompanied by a 6 percentage point increase in availability. These results are driven largely by the improvements in operating reliability at EGUs with lower nameplate capacity. My results are not driven by the decommissioning of old and inefficient EGUs or a commissioning of new more efficient ones, thus representing an improvement at existing capacity. This is an important distinction as increasing reliability at existing units (improvement on the intensive margin) can likely be achieved more cheaply than by installing new capital equipment (the extensive margin).[4]

[4] A comparison of costs of efficiency increases on the intensive and extensive margins would help quantify gains. However, such data is not available.

On average, there is no evidence of an improvement in capacity utilization due to restructuring, although the results suggest a statistically significant increase at some EGUs. For states that unbundled prior to 2003, I find that unbundling led to a significant improvement in electricity generation at smaller generating units—a 9.4 percentage point increase in capacity utilization at 110/120 MW units. Importantly, my results show no evidence that unbundling of SEBs led to the improvement in thermal efficiency at state-owned power plants.

In summary, my analysis points to modest gains from reform. Operating reliability increased at EGUs in states that unbundled prior to 2003; but there is no evidence of an improvement in thermal efficiency. My failure to find a larger impact from restructuring than reported in the US may also reflect the path that reform has taken in India thus far. In the United States unbundling resulted in independent power producers (IPPs) entering the market for generation. This has not yet occurred on a large scale in India.

The rest of the paper is organized as follows. Section 2 provides background on the Indian power sector and the nature of reforms. Section 3 describes the empirical approach taken. In section 4, I discuss econometric issues. Section 5 describes the data used in the study and section 6 my results. Section 7 concludes.

2. Background

2.1 Overview of the Indian Power Sector

Most generating capacity in India is government owned. The 1948 Electricity Supply Act created State Electricity Boards (SEBs) and gave them responsibility for the generation, transmission, and distribution of power, as well as the authority to set tariffs. SEBs operated on soft budgets, with revenue shortfalls made up by state governments. Electricity tariffs set by SEBs failed to cover costs, generating capacity expanded slowly in the 1960s and 1970s, and blackouts were common. To increase generating capacity, the Government of India in 1975 established the National Hydroelectric Power Corporation and the National Thermal Power Corporation (NTPC), which built generating capacity and transmission lines that fed into the SEB systems. In 1990, prior to reforms, 63 percent of installed capacity in the electricity sector in India was owned by SEBs, 33 percent by the central government, and 4 percent by private companies (Tongia 2003).

My analysis focuses on coal-fired power plants, which have, for the past two decades, provided approximately 70% of the electricity generated in India.[5] Coal-fired power plants in India are, in general, less efficient than their counterparts in the US. Over the period 1988-1995 the average operating heat rate—the heat input (in kcal) required to produce a kWh of electricity—of state-owned plants was 30 percent higher than the average operating heat rate of comparable plants in the United States during the period 1960–1980 (Joskow and Schmalensee 1987).[6]

The higher average operating heat rates of Indian plants are due in part to the poor quality of Indian coal, but also to inefficiencies in management. The design heat rate of generating units that use coal with high moisture and/or high ash content is higher than for

[5] In 2009-10 (CEA 2010) 53% of installed capacity connected to the grid was coal-fired, 11% fired by natural gas, 23% hydro, 3% nuclear and the remainder renewables; however 70% of electricity was generated by coal-fired power plants.
[6] See Table 3B. I focus on the operating heat rate of state-owned plants, as data on operating heat rate of central-government-owned plants are often not reported in the Central Electricity Authority's Thermal Power Reports (various years).

units with low moisture and ash content (MIT 2007). The ash content of Indian coal is between 30 and 50% (Khanna and Zilberman 1999). This implies that Indian plants will require more energy to produce a kWh of electricity than comparable plants in the US. The operating heat rate of the plant may be higher than the design heat rate if the plant is poorly maintained or experiences frequent outages.[7] Pre-reform, operating heat rates at state-owned plants were, on average, 31% higher than design heat rates (Cropper et al. 2011).

State plants have, historically, been operated less efficiently than plants owned by the central government: they have had higher forced outages and lower capacity utilization. Figure 1 illustrates trends in the average percent of time state and central plants were available to generate electricity (plant availability), the average percent of time plants were shut down due to forced outages, and the average percent of time the plant was used to generate electricity (capacity utilization). State power plants have, on average, had lower availability and capacity utilization than central-government-owned plants and higher forced outages throughout the 1988-2009 period.

2.2 History of Power Sector Reforms

Electricity sector reforms in India were prompted by the poor performance of state-owned power plants, by large transmission and distribution losses, and by problems with the SEBs' tariff structure. The tariff structure, which sold electricity cheaply to households and farmers and compensated by charging higher prices to industry, prompted firms to generate their own power rather than purchasing it from the grid, an outcome that further reduced the revenues of SEBs. The result was that most SEBs failed to cover the costs of

[7] Whenever a plant is started up after an outage, more coal is burned than during the normal operation of the plant.

electricity production. Reform of the distribution network was necessary because of the extremely large power losses associated with the transmission and distribution of electric power—both technical losses and losses due to theft (Tongia 2003).

Beginning in 1991, the Government of India instituted reforms to increase investment in power generation, reform the electricity tariff structure, and improve the distribution network. Under the Electricity Laws Act of 1991, IPPs were allowed to invest in generating capacity. They were guaranteed a fair rate of return on their investments, with tariffs regulated by Central Electricity Authority. The Electricity Regulatory Commissions Act of 1998 made it possible for the states to create State Electricity Regulatory Commissions (SERCs) to set electricity tariffs. States were to sign memoranda of understanding with the federal government, agreeing to set up SERCs and receiving, in return, technical assistance to reduce transmission and distribution losses and other benefits. The Electricity Act of 2003 made the establishment of SERCs mandatory and required the unbundling of generation, transmission, and distribution (Singh 2006).

There were two distinct waves of unbundling reforms in India. Table 1 shows the year in which the SERC became operational in each state and the year in which generation, transmission, and distribution were unbundled.[8] The first wave, between 1996 and 2002, took place prior to the Electricity Reform Act of 2003. The second wave began in 2004 and continued through the end of my sample period (2009).[9] I refer to these as Phase 1 (unbundling prior to 2003) and Phase 2 (unbundling between 2004 and 2009) states. The

[8] Table 1 lists only those states containing thermal power plants. My study focuses on coal- and lignite-fueled plants.
[9] Assam unbundled in 2004, but its only coal-fired power plant was decommissioned in 2001-02. I retain Assam in the dataset; however, for Phase 2 plants, the first year of unbundling is, effectively, 2005, the year in which Maharashtra unbundled.

remaining states (Phase 3 states) unbundled either outside of my sample period or have not unbundled as of 2012.

Why did certain states restructure their electricity sectors before others? A plot of Table 1 on a map suggests that there is no particular geographic pattern to unbundling. Whether a state restructured its electricity sector is also unrelated to the financial losses it was suffering prior to reform or to its electricity deficit—the difference between electricity supply and peak electricity demand. Figure 2 plots states that unbundled before and after the 2003 Electricity Act (i.e., Phase 1 v. Phase 2 and 3 states) against various factors that might have influenced the timing of unbundling. Panels A and B of Figure 2 show that there is no evidence of a relationship between either the electricity deficit in the state, pre-reform or the losses suffered by the SEB (the ratio of revenues to costs) and the timing of unbundling. Panel C suggests that states with a higher proportion of renewable electricity generation did unbundle earlier. Renewable capacity is largely hydro power and is thus determined by exogenous geographical features. Panel D shows that states with lower subsidies to agricultural consumers (a higher ratio of agricultural to industrial tariffs) were also more likely to unbundle earlier.[10]

2.3 Impacts of Electricity Sector Reforms

It is important to ask how unbundling reforms might affect the operating reliability of plants or their thermal efficiency. The separation of generation from transmission and distribution services could improve generation efficiency in several ways. Unbundling may result in an increase in generator efficiency from "corporatization"—plant managers being

[10] I also check whether state economic well-being (per capita income and electricity consumption) drives reform. I find no evidence to suggest that either of these determined the timing of unbundling reforms.

given greater discretionary powers to minimize costs and having to face hard budget constraints. Unbundling may also improve efficiency by reducing diseconomies of scope—allowing managers to focus on decisions related solely to generation. This may result in more timely maintenance decisions and lead to increase generator reliability through reduced breakdowns and forced outages.

The scope for such performance improvements is illustrated by comparing management practices at state and central government owned power plants (ESMAP 2009). The differences in plant availability and capacity utilization at central-government owned plants pre-reform (Table 3A) are due to greater forced outages and more time spent on planned maintenance at state plants, although capital equipment at both sets of plants is, on average, of the same age. Time spent on planned maintenance can be reduced by better scheduling of maintenance and better inventory management. Better management of information can help address and avoid technical problems that result in forced outages.[11]

Differences in fuel efficiency can also be driven by factors related to manpower. At the plant-level, Bushnell and Wolfram (2007) document differences in plant operator skill and effort levels that lead to significant differences in plant efficiency. While some processes are automated, activities such as controlling the rate at which pulverized coal is fed to burners, adjusting the mix of air and fuel in the mills, and operating soot blowers in boilers crucially depend on the plant operator's skill and effort levels.

[11] The main technical problems at state plants identified by ESMAP (2009) include poor condition of boiler pressure parts due to overheating and external corrosion, poor water chemistry, poor performance of air pre-heaters and poor performance of the milling system.

The incentives for improving fuel efficiency and maintaining equipment to prevent breakdowns depends on how plants are compensated. Under the 2003 Electricity Act SERCs are to follow the Central Electricity Regulatory Commission's (CERC's) guidelines in compensating generators. The CERC compensates the power plants under its jurisdiction based on performance. Compensation for energy used in generation is paid based on scheduled generation and depends on operating heat rate. Compensation for fixed costs (depreciation, interest on loans and finance charges, return on equity, operation and maintenance expenses, interest on working capital, and taxes) is based on plant availability.

How have SERCs actually compensated power plants? There is evidence that SERCs have set compensation for fuel use based on very high estimates of operating heat rate, suggesting that this may not provide much of an incentive for plants to improve thermal efficiency (Crisil Ltd. 2010).[12] Compensation for fixed costs based on availability has occurred and is meant to prevent plants from supplying excess electricity to the grid, as was the case historically when plants were compensated based on capacity utilization.

Another avenue through which reforms could influence plant reliability and thermal efficiency is through investment in new equipment. Between 1995 and 2009 coal-fired generation capacity in India increased by 31 percent. It increased by 45% in Phase 1 states, by 30% in Phase 2 states and by 5% in Phase 3 states. An important policy question is the extent to which reforms improved the performance of EGUs installed pre-reform versus

[12] The general focus on increasing electricity supply in the Indian electricity sector may also take away from the incentives to increase thermal efficiency (reduce heat rates).

impacts that occurred through the installation of new equipment. I test this by estimating models using only EGUs in operation pre-reform as well as using all EGUs.

3. Empirical Strategy

To examine the impact of restructuring on the operating efficiency of state owned power plants, I use EGU-level data on measures of operating reliability and plant-level data on thermal efficiency as outcome variables. Operating reliability is measured by the percentage of time in a year an EGU is available to generate electricity (unit availability), and the percentage of time a unit is forced to shut down due to equipment failures (forced outage).[13] Thermal efficiency is measured by coal consumption per kWh and by operating heat rate. I also estimate the impact of reform on the capacity utilization of the EGU (percent of time the EGU generates electricity).

The time variation in restructuring across states allows me to use a difference-in-difference (DD) estimator. Figure 3 shows the proportion of EUGs in states that have restructured, by year. With data at the EGU-level, I estimate the impact of unbundling on generation efficiency controlling for time-invariant characteristics of EGUs, year fixed effects and linear time trends specific to each state.[14] The baseline model is estimated using the following specification,

[13] The percentage of time a unit is available equals the 100 percent minus the percent of time spent on planned maintenance and the percent of time lost due to forced outages.

[14] Aghion et al. (2008) use similar specifications to estimate the impact of the dismantling of the licensing regime in India on manufacturing output. They take advantage of state and industry variation in industrial policy to estimate a difference-in-difference model of the incidence of delicensing on output. Besley and Burgess (2004) conduct a state-level panel analysis estimating the effect of labor regulation on state output per capita.

$$Y_{ist} = \emptyset 1[Unbundled]_{st} + X_{ist}\beta + \sum \mu_s TREND_{st} + \tau_t + \theta_i + \varepsilon_{ist} \quad \ldots (1)$$

where Y_{ist} is the measure of generation efficiency for EGU *i* in state *s* in year *t*. In the thermal efficiency models, *i* refers to the plant, as data for operating heat rate and specific coal consumption are available only at the plant level. The variable of interest is $1[Unbundled]_{st}$, a policy indicator that takes a value of 1 starting in the year after state *s* unbundles its SEB; $\emptyset$ thus estimates the average effect of the policy. A positive and statistically significant estimate of $\emptyset$ for unit availability and capacity utilization and a significant negative estimate for forced outage, specific coal consumption and heat rate is evidence of an average improvement in the efficiency of generation as a result of reform.

All baseline specifications estimate the impact of reforms controlling for EGU/plant fixed effects, θ_i, and year fixed effects, τ_t. The inclusion of fixed effects controls for all time-invariant characteristics that affect the generation performance of an EGU or plant. The inclusion of year dummies captures macroeconomic conditions and changes in electricity sector policy that affect generation in the country as a whole.[15] The upward trend in operating reliability at both state and central plants throughout the sample period (see Figure 1) implies that without year fixed effects estimates of the impact of unbundling would be overestimated. Estimates of the effects of unbundling may also be biased due to differing pre-reform trends between states that restructured their SEBs and

[15] In 2003 an Unscheduled Interchange charge was instituted throughout the country to compensate (penalize) plants supplying unscheduled electricity to the grid when there is excess demand (supply).

those that did not. To control for this, the baseline specifications include state-specific time trends, $TREND_{st}$.

The estimated models also control for EGU and plant level characteristics that directly affect generation performance. The EGU models include a quadratic age term.[16] The thermal efficiency regressions include average unit capacity in the plant, the heating content of coal (gross calorific value per kg), the average design heat rate and a quadratic term in average plant age.

To examine whether the impact of unbundling varies with the phase of unbundling, I estimate a variant of (1) that interacts the unbundled variable with indicators for Phase 1 and Phase 2 states,

$$Y_{ist} = \sum_{k=1,2} \emptyset_k . 1[PhaseUnb]_{kst} + X_{ist}\beta + \sum \mu_s TREND_j + \tau_t + \theta_i + \varepsilon_{ist} \qquad \dots (2)$$

$1[PhaseUnb]_{kst}$ takes the value of 1 after unbundling of the SEB in state s belonging to group k (k = Phase 1, Phase 2) and $\emptyset_k$ is the estimate of the impact of unbundling for state-group k relative to the counterfactual of not having unbundled by 2009—the last year of the data.

In addition to examining heterogeneous treatment effects, I test for persistence in reform impacts over time. To do this, I interact the unbundled variable with a set of biennial dummy variables post reform; these measure the impact of reform 1-2 years after reform,

[16] Other characteristics such as capacity, vintage and make of boiler/EGU also impact generation performance, but are time-invariant and thus subsumed by the EGU fixed-effects.

3-4 years after reform, and so on. Estimation of dynamic duration effects is of interest for two reasons. First, it is important to check whether reforms result in a persistent change in operating efficiency at unbundled power plants. A temporary increase in efficiency followed by a reversion to the mean may still yield a positive, significant average treatment effect in the short-term.

Second, Wolfers (2006) points out the potential for bias in estimating average treatment effects when panel-specific trends are included in a difference-in-difference analysis. Since the average treatment effect captures the average deviation from trends in the post-treatment period, incorrectly estimated pre-treatment trends cause the estimate to be biased. This problem is most severe when the estimation sample contains a relatively short pre-treatment period. In this case, a reversal of the trend in the post-treatment period would have a disproportionate effect on estimates of the trend coefficients. Allowing full flexibility in post treatment impacts enables the trend slope coefficients to be determined by the pre-treatment period trends and allows me to examine the evolution of efficiency increases after unbundling reform.

The estimate of dynamic effects of reform relies on the following specification,

$$Y_{ist} = \sum_{t=1,3,5,..} \sum_{k=1,2} \emptyset_k^t 1[PhaseUnb]_{kst} D_t^{t+1} + X_{ist}\beta + \sum_{s=1}^{17} \mu_s TREND_j + \tau_t + \theta_i + \varepsilon_{ist}$$

… (3)

In equation (3) the unbundling variable is multiplied by a set of indicator variables that represent the number of years since the reform. D_t^{t+1} = 1 if between t and $(t+1)$ years have elapsed since the reform and $\emptyset_k^t$ estimates the average impact for the same time period.

4. Econometric Issues and Identification

An obvious concern in estimating the impacts of reform is that the adoption of reforms across states may be endogenous, thus biasing estimated impacts. Endogeneity may result from state officials explicitly considering potential efficiency improvements in deciding when to implement reforms, or from unobserved heterogeneity across states that drives both the decision to reform and improvements in power plant performance. If states where power plants were likely to gain most from reform were more likely to reform first, the estimated coefficient on the reform dummy would be biased upward. Alternatively, states with greater institutional capacity may be quicker to reform and more likely to benefit from it—also resulting in a positive bias. Although it is impossible to rule out all sources of bias, my estimation strategy and the institutional context of power sector reforms in India should reduce endogeneity concerns.

First, the inclusion of EGU fixed effects controls for any time-invariant differences across EGUs, including factors such as state location (vis-à-vis coal mines and the transmission grid) and institutional capacity (which may be regarded as fixed over the sample period). The inclusion of state-specific time trends controls for any linear time-varying unobserved differences across states and addresses the concern that adoption of reform may be associated with pre-existing trends in power plant performance.

Second, the adoption of reform was a decision taken at the state level by bureaucrats and politicians. It is more likely that political factors determined the decision to restructure state electric utilities than beliefs about generation efficiency. Tongia (2003) cites opposition from the agricultural sector as a factor that delayed the adoption of reforms by some states, given that one objective of reforms was to reduce subsidies to agricultural consumers. The political importance of agricultural constituencies may have delayed the adoption of even the initial stages of reform (i.e., unbundling);[17] however, this is unlikely to bias estimates of generation efficiency.

A third econometric concern is that the coefficient on unbundling may be capturing non-linear time-varying factors that are specific to the state but not related to unbundling. To account for this possibility I take advantage of the presence of power plants owned by the central government that operate in many states across the country. These power plants are owned and operated by the National Thermal Power Corporation (NTPC) and the Damodar Valley Corporation (DVC). They operate outside the structure of the SEBs and are thus not directly affected by restructuring.[18]

To account for state-specific non-linear year shocks, I employ a triple-difference (DDD) specification that includes central power plants and uses state-year dummy variables,

$$Y_{iost} = \emptyset\, 1[Unbundled]_{sot} + X_{ist}\beta + \theta_{\{ot\}} + \psi_{\{st\}} + \nu_i + \epsilon_{\{ist\}} \quad \text{... (4)}$$

[17] It is not surprising that Orissa was the first state to reform, given the (un)importance of farming in the state.

[18] To confirm this, I conduct a falsification test to estimate the impact of state SEB unbundling on operating reliability of central EGUs using equations (1) and (2). The impact is statistically indistinguishable from zero.

In equation (4), $Y_{\{isot\}}$is the outcome at EGU i in state s under ownership o in year t. $\theta_{\{ot\}}$ represents the full set of ownership (state/central) year effects and $\psi_{\{st\}}$ represents the full set of state-year effects. The specification thus controls for time effects in each state and time effects for each ownership type. The estimate of the impact of unbundling, $\emptyset$, is identified by the variation in ownership-state-year (as compared to state-year variation that identifies the estimate in the DD specification).

The DDD estimate takes the following form,

$$\emptyset^{\{DDD\}} = \left[\Delta^t Y_{\{U\}} - \Delta^t Y_{\{B\}}\right]_{\{state\}} - \left[\Delta^t Y_{\{U\}} - \Delta^t Y_{\{B\}}\right]_{\{center\}} \quad \dots (5)$$

where $\Delta^{\mathrm{t}}\mathrm{Y}_{\{\mathrm{U}\}}$ is the change in the outcome post reform for states that unbundle and $\Delta^t Y_{\{B\}}$ is the corresponding change for non-reforming states. The difference of these values for center-owned EGUs is subtracted from the difference for state-owned EGUs to obtain the estimate of the impact of unbundling reform.

5. Data

I use data from the Central Electricity Authority of India's Performance Review of Thermal Power Stations (CEA various years) to construct an unbalanced panel of 385 EGUs for the years 1988–2009.[19] Of the 385 EGUs, 270 operate in 60 state-owned generation plants and 115 are in 23 central-government-owned plants. The units in the dataset constitute 83 percent of the total installed coal-fired generation capacity in the

[19] The CEA reports are not available for the years 1992 and 1993. These years are thus omitted from my data. A year in the dataset is an Indian fiscal year. Thus, 1994 refers to the time period April 1, 1994, through March 30, 1995.

country in the year 2009–2010.[20] Additional information on the date that the SERCs were established, the date of the unbundling reforms for each state and ownership information for each power plant was obtained from the websites of the individual SERCs and the CEA.

Tables 2A and 2B present summary statistics that compare state EGUs (Table 2A) and plants (Table 2B) by phase of reform in the period prior to restructuring (1988–1995) and at the end of the sample period (2006–2009). Tables 3A and 3B present similar comparisons between state and central EGUs (Table 3A) and plants (Table 3B).

Prior to the first unbundling reforms in 1996, Phase 1 states were performing slightly worse than other states. The EGUs in these states were older, smaller, had higher forced outages, slightly lower availability and lower thermal efficiency compared to Phase 2 states. This pattern was reversed by 2006-09: Phase 1 states were now statistically indistinguishable in terms of performance measures—forced outages, availability, capacity utilization—from Phase 2 states.[21] Operating heat rate at plants in Phase 1 states was also slightly below operating heat rate in Phase 2 states by 2006-09, although the difference is not statistically distinguishable. This suggests that between 1996 and 2006 the states that unbundled early (Phase 1 states) outperformed the states that were just beginning to unbundle their SEBs in 2004 (Phase 2 states). The tables also show a drop in the average design heat rate of plants in Phase 1 states, which implies that at least a part of the gains in average performance measures are due to the addition of newer and more efficient units.

[20] Nine percent of coal-fired generation capacity in 2009-10 was privately owned.

[21] Average forced outage was lower in Phase 1 states compared to Phase 2 in the period 2006-09; however, the difference in means is not statistically significant.

The comparison between state and central plants In Tables 3A and 3B confirms that central plants were significantly more efficient than state plants throughout the sample period. Over the years 1988–1995, the average capacity utilization of state EGUs was about 10 percentage points lower than EGUs at centrally owned plants. Coal consumption per kWh was about 7 percent higher at state plants. A comparison of operating heat rates at state and central plants is more difficult, as data are often missing for plants operated by the National Thermal Power Corporation (NTPC).

During the sample period, both state and central plants improved in reliability, but showed little improvement in thermal efficiency. Table 3 indicates that EGUs in both sets of plants have experienced large gains in capacity utilization (an average increase of 19 percentage points for state and 25 percentage points for central plants) and smaller gains in plant availability (an average increase of 13 percentage points for both central and state plants). Forced outages also decreased substantially at both sets of plants. There was, in contrast, little change in coal consumption per kWh.

6. Results

6.1 Difference-in-Difference Results for Thermal Efficiency

I measure the impacts of unbundling on thermal efficiency using both specific coal consumption (kg/kWh) and operating heat rate (kcal/kWh). The models are estimated using plant-level data. Plants owned by the central government cannot be used as controls since data on thermal efficiency are often missing for these plants.

Coal burned per kWh depends on the design heat rate of the boiler (e.g., boilers designed to burn high-ash coal have higher design heat rates and thus require more coal), the heating value of the coal burned, and the age and capacity of the boiler (Joskow and Schmalensee 1987). Coal consumption per kWh should decrease with the heating value of the coal and capacity of the boiler and should increase with boiler age.[22] In estimating models of coal consumption I treat the heating value of the coal as exogenous to the plant. Given the structure of the Indian coal market, plant managers cannot choose coal quality. Power plants are linked to coal mines by a central government committee and thus have little leeway in determining the quality of the coal received.[23]

Operating heat rate (OPHR) is the sum of coal burned per kWh, multiplied by the heating value of the coal, plus oil burned per kWh, multiplied by the heating value of the oil. Although OPHR captures oil as well as coal usage, I expect the impact of unbundling on operating heat rate to be similar to its impact on coal consumption per kWh.[24] One way in which restructuring could reduce coal consumption and operating heat rate are through the purchase of newer generating equipment. This should improve thermal efficiency because boilers generally deteriorate as they age and, new boilers embody technical improvements. It is also possible to improve thermal efficiency by pulverizing coal before it is burned and by performing regular maintenance of boilers. By holding equipment age constant in my thermal efficiency models I focus on the change in efficiency due to managerial factors.

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[22] Because my models are estimated at the plant level, variables measured at the level of the EGU (such as age) have been aggregated to the plant level by weighting each unit by its nameplate capacity. The average nameplate capacity is a simple average of EGU capacity in the plant.

[23] The use of washed (beneficiated) coal, which has a higher heating value, is also mandated through regulation and not determined by plant managers.

[24] Because coal constitutes most of the kcal used to generate electricity, OPHR ≈ (Coal per kWh)*(Heating Value of Coal). It follows that the coefficient of ln(Heating Value of Coal) in the ln(OPHR) equation should approximately equal 1 plus the coefficient of ln(Heating Value of Coal) in the ln(Coal Consumption per kWh) equation. My results confirm this.

Table 4 indicates that after controlling for plant characteristics, year dummy variables and state-level trends, there is no evidence to support the hypothesis that unbundling improved the thermal efficiency of state-owned power plants. Plant characteristics have the expected signs; however, average treatment effects in columns [1] and [2] show no significant impact of unbundling on operating heat rate and a significant positive impact on specific coal consumption. Examining the heterogeneous impacts in column [3] and [4] reveals that plants in Phase 2 states experience a statistically significant worsening in thermal efficiency post unbundling reforms—this is also what drives the average impact of specific coal consumption in column [2]. This result is consistent with large increases in specific coal consumption observed in Gujarat and Maharashtra beginning in 2005. These increase could be due to idiosyncratic shocks to the quality of coal (e.g., to its ash and moisture content) for which I do not have data.

My results, which show no significant improvement in thermal efficiency as a result of restructuring, are consistent with the results of Hiebert (2002) and Fabrizio et al. (2007). Hiebert find mixed effects of restructuring on the technical efficiency of coal-fired power plants in US states that restructured their electricity sectors (improvements in 1996 but not in 1997). Fabrizio et al. (2007) find no improvement in fuel input usage at plants in states that restructured their electricity sectors. It should, however, be noted that both studies look at the impacts of restructuring shortly after states separated generation from distribution. My panel follows plants in Phase 1 states for an average of 10 years after unbundling.

6.2 Difference-in-Difference Results for Operating Reliability

Columns [1] and [2] of Table 5 show the average effect of unbundling of SEBs on unit availability and forced outage. Availability is the percentage of hours in a year that the EGU is available to produce electricity; forced outage is the percentage of time that the EGU is forced to shut down due to breakdowns and mechanical failures. The results in Column [1] and [2] indicate that the average impact of unbundling on state EGUs is statistically insignificant from zero.

Columns [3] and [4], however, show that states that unbundled prior to the Electricity Act of 2003 experienced a statistically significant improvement in operating reliability: average EGU availability increased by 6.8 percentage points. This increase represents a 10 percent increase over 1995 levels. The improvements in availability were largely driven by a reduction in forced outages. The unbundling of generation resulted in a 5.1 percentage point reduction in the time lost from breakdowns, a 25 percent reduction from average forced outage for these states in 1995.

Column [3] shows a decline in EGU availability in Phase 2 states due to unbundling that is significant at the 10 percent level, but no statistically significant impact on forced outages. Because plant availability, forced outages and planned maintenance must sum to 100 percent, this implies that the reduction in availability is due to increased plant maintenance. This is a very different outcome than an increase in forced outages and need not represent a decline in efficiency.

An underlying assumption of the standard difference-in-difference specification is the equality of pre-existing trends between the treatment and control groups. Though my specifications control for state-specific trends, I examine the whether operating reliability was trending similarly at EGUs across states in different phase groups prior to reform.[25] Figure A1-A3 of Appendix A compares the trends in availability, forced outage and capacity utilization for the period 1988-1995. The graphs suggest that the trends were broadly similar across the phase groups and thus are not likely to bias the estimated policy impact.

Table 6 presents robustness checks for the operating reliability models. These indicate that the reduction in forced outages in Phase 1 states is robust to sample specification and representation of time trends. For Phase 1 states the increase in EGU availability and reduction in forced outages is affected only slightly by dropping Phase 2 states from the models (i.e., to using only states that did not restructure during the sample period as a control group). This is also the case when state time trends are replaced by time trends for the three phases of unbundling.

Table 6 also investigates the impact of the decommissioning and commissioning of EGUs on my results. Columns [5] and [6] re-estimate the models dropping observations for the EGUs that were shut down during the sample period. This eliminates the possibility that units that were shut down are driving the results in Table 5. This slightly reduces the impact of unbundling on forced outages and plant availability, to -3.7 and 4.9 percentage points, respectively. To test whether it is new EGUs that are driving the results I estimate the models using EGUs that were installed pre-reform and remain in the dataset through 2009 (columns [7] and [8]). Columns [7] and [8] suggest that unbundling significantly

[25] As the trends are estimated on both pre- and post-period data, a break in trend due to the policy change may implies that state-trends may not adequately control for trend differences in the pre-period.

improved the performance of existing equipment in Phase 1 states, reducing forced outages by about 5 percentage points and increasing availability by about 6 percentage points.

As is the case for Phase 1 states, results for Phase 2 states are also robust to choice of sample. The reduction in availability at Phase 2 plants remains statistically significant and is associated with increased restoration and maintenance of EGUs, rather than an increase in forced outages.

6.3 Triple-difference Estimates of Operating Reliability

The triple-difference (DDD) specifications include EGUs at central power plants as an additional control group. The validity of central power plants as a control group rests partly on SEB reforms having no impact on the operating reliability of these plants. To test this, I estimate a model of the impacts of SEB restructuring on EGUs at central power plants. The results, presented in Appendix A, show that there is no evidence of unbundling reforms on operating availability or forced outages at central EGUs—the magnitude of the coefficients is small and the standard errors are large.

Table 7 presents the results from the DDD estimation of the impact of unbundling, by phase. The results in Table 7 are qualitatively similar to those in Table 5 for the DD specification. The coefficient estimates in columns [1] and [2] show a statistically significant increase in availability of 6 percentage points—equivalent to an additional 700 MW becoming available for electricity production—and a decrease in forced outage for EGUs in Phase 1 states of 5 percentage points. These results are robust to dropping from the sample units that were shut down (columns [3] and [4]). Results for Phase 2 states, although qualitatively similar to Table 5, are no longer statistically significant. When the

DDD model is estimated using EGUs that were installed pre-reform and remain in the dataset through 2009, the impact of unbundling on forced outages is unaffected, suggesting that reforms improved existing capacity; however, the impact on availability is estimated less precisely.

All results presented above are with standard errors clustered at the state level. This takes into account possible correlation in outcomes across EGUs within states and over time (Bertrand et al. 2004). Since all EGUs within a state are owned by the SEB of that state[26], clustering at the state level is appropriate. However, since the number of states is small, the number of clusters may not be sufficient to provide consistent estimates of the cluster robust standard errors. In Appendix A I present the main results with clustering at the level of a power plant (Table A5 and A6) and clustering at the state level (Table A7) using wild cluster bootstrap-t procedure (Cameron et al. 2008). The results are qualitatively similar to those presented above and thus I proceed with state level clustering for the rest of the analysis.

6.4 Dynamic Effects of the Impact of Unbundling

The average treatment effects for units in Phase 1 states could reflect an initial impact of restructuring that declined over time. My analysis of the dynamic impacts of restructuring suggests that this is not the case. Using equation (3), I estimate the impact of unbundling by interacting a series of biennial dummy variables with the unbundling

[26] Except the EGUs owned by the Central government generators that are included in the DDD specifications.

variables. Figures 4A to 4D plot the estimated coefficients of time dummy variables that represent two-year intervals after reform for Phase 1 states.[27]

Figures 4A and 4B show a similar pattern of the impact on forced outage for both DD (Figure 4A) and DDD (Figure 4B) specifications. The DD coefficients are, however, less precisely estimated. The DDD estimates in Figure 4B suggest a lag in the reduction of forced outages after unbundling for Phase 1 states. The impact is significant starting 3 years after unbundling, and is largest 3, 5 and 9 (or more) years after reform.

Figures 4C and 4D plot the results from a more flexible specification of the DDD model. Here, I allow both the pre- and post-reform time effects for state-owned EGUs to vary non-parametrically.[28] Figure 4C shows that the flexible estimation of the pre-reform trend in forced outage at state-owned EGUs yields a flat trend, conditional on covariates. The evolution of the impact after unbundling is the same as in figure 4B above. Figure 4D indicates that the significant reform impacts on availability for Phase 1 states persist for the duration of the sample.

6.5 Impacts on Capacity Utilization

Did the reductions in forced outages and increases in availability at EGUs in Phase 1 states result in greater electricity production? Table 8 suggests that, on average, increases in availability were not reflected in increased capacity utilization of state-owned EGUs. Column [1] and column [2] report the impacts, by phase, from the DD and DDD

[27] The dummy year categories are 1-2 years, 3-4 years, 5-6 years, 6-7 years and 9+ years since unbundling. The last category captures up to 13 years after unbundling in the case of Orissa. I combine years greater than 9 into one dummy because the number of observations is too low to estimate finer categories.
[28] This is similar to an event study specification.

specifications. I find no evidence to suggest that, on average, unbundling generation from transmission and distribution led to an increase in capacity utilization at state EGUs.

This result is at variance with the results of Sen and Jamasb (2012) who, using state-level data, find that unbundling resulted in a 26 percentage point increase in capacity utilization at state-owned power plants. Interestingly, average capacity utilization at state-owned EGUs increased by roughly 25 percentage points from 1991 to 2009 (see Figure 1C). However, once I control for plant and year fixed effects and state time trends, this result is unrelated to unbundling.

One reason why increases in availability did not result in greater electricity generation may be that they occurred at higher cost plants. If these plants were not able to underbid lower cost plants in the merit dispatch order, increased availability would not necessarily result in increased capacity utilization. Alternatively, it could also be that there was heterogeneity in the impacts of unbundling on capacity utilization which caused the average effect to be estimated noisily. I note that the sign of the impact of unbundling on average capacity utilization in Table 8 is positive but insignificant for Phase 1 states, suggesting this possibility.[29] I examine the nature of heterogeneity in the impact of reforms by estimating models that allow for differential impacts by EGU size.

Table 9 presents difference-in-difference models which interact the Phase-specific unbundling variable with categorical variables for 4 EGU size categories—EGUs less than 100 MW, 110/120 MW, 210/220/250 and 500 MW.[30] The results show that 110/120 MW

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[29] The magnitude of the average term may be reduced due to gains in capacity utilization (or reliability) at some generators and possible deterioration at others—e.g. due to adjustment costs of restructuring.
[30] I define each group based on a range of nameplate capacities that is largely composed of these capacities.

units experienced a significant positive increase in operating reliability in Phase 1 states: operating availability increases by about 12 percentage points, largely driven by a 9 percentage point reduction in time lost due to forced outages. The increase in operating availability translated into a roughly 9 percentage point increase in capacity utilization at these EGUs. Indeed, the results in Tables 5-8 appear to be driven by reductions in forced outages at small (100 MW and 110/120 MW) plants.

The estimates for Phase 2 states suggest that the impact of unbundling was to decrease EGU reliability. There is a statistically significant decline in availability which leads to a decline in capacity utilization. The estimates also show that the deterioration associated with reforms at EGUs in Phase 2 states is not due to an increase in forced outage. Thus an increase in maintenance is driving the observed decreases in availability and capacity utilization. As argued above, it is questionable whether this captures a reduction in efficiency due to reform.

7. Conclusions

This paper examines the impact of reforms in the Indian electricity sector on the generation performance of state-owned power plants. My results show that unbundling resulted in a statistically significant increase in the average availability of EGUs in states that restructured their SEBs prior to the Electricity Act of 2003. I find that the increase in availability at these EGUs is mainly driven by a corresponding reduction in forced outages. There is no evidence of an impact of restructuring on average capacity utilization or improvements in thermal efficiency. In fact, the results show a statistically significant increase in coal consumption per kWh and in operating heat rate at state plants in states that unbundled between 2005 and 2009.

Results from a triple difference specification suggest a 5.9 percentage point increase in average unit availability and a 4.9 percentage point reduction in forced outages in Phase 1 states. The reduction in forced outages represents a 25 percent reduction from the mean for these states in 1995. Examination of the duration of reform impacts, using a full set of pre and post time dummies, shows that the improvements in generation reliability are not reversed in the short to medium term. Robustness checks confirm that my baseline results are not sensitive to changes in model and sample specifications.

The estimation of the average impact of unbundling hides the considerable heterogeneity in the impact of reform by EGU characteristics. Smaller EGUs experienced a significant increase in operating reliability due to reform in Phase 1 states. In Phase 1 states, 110/120 MW EGUs experienced a 9.4 percentage point increase in capacity utilization driven largely by a reduction in the time lost due to forced outage. The increase in capacity utilization represents a 24 percent increase above the 1995 average (39 percent) at 110/120 MW EGUs and implies an additional 2083 GWh of electricity production per year from these units.[31]

For Phase 2 states, my results suggest that the initials years following reforms were associated with a reduction in availability and capacity utilization, especially at 110/120 MW EGUs, and a decrease in thermal efficiency. The estimated coefficients are unstable

[31] State-owned thermal power plants generated 240.8 TWh (10^3 GWh) of electricity in 2005 (CEA 2006). This figure includes gas-fired plants.

and often insignificant, but suggest a worsening in generation performance across various specifications. The estimated deterioration in performance may be due to initial adjustment costs to restructuring in the states that were forced to unbundle. It should also be noted that the reductions in availability at EGUs are due to increases in planned maintenance rather than increases in forced outages.

The offsetting deterioration in Phase 2 states implies that, on average, the impact of reforms has been modest in magnitude. It is safe to say that the gains from unbundling reforms have thus far been limited to an improvement in operating reliability and capacity utilization for the most inefficient plants in the states that unbundled prior to 2003.

To the extent that I find modest impacts of restructuring on operating reliability due to a reduction in forced outages—and no improvements in thermal efficiency—my results are comparable to those of Fabrizio et al. (2007) and Davis and Wolfram (2011) for the US. Fabrizio et al. (2007) do not find evidence of the impact of restructuring on the thermal efficiency of power plants, although they do find significant reductions in non-fuel expenditures. Davis and Wolfram (2011) find that deregulation and consolidation in ownership led to a 10 percentage point increase in operating efficiency nuclear power plants—driven largely by reductions in forced outages.

My results disagree with those of Sen and Jamasb (2012) who, using state-level data for India, find that unbundling increased average capacity utilization by 26 percentage points—an extremely large effect. One possible explanation for the difference is that the Sen and Jamasb (2012) may not adequately control for the strong upward trend in the capacity utilization at Indian power plants during the period of their study (see Figure 1C).

The failure to find more widespread impacts from restructuring may reflect the nature and progress of electricity reform in India thus far. Ruet (2005) argues that unbundling and subsequent corporatization has failed to increase the technical and financial autonomy of power plant managers to the extent envisaged at the start of reforms. Executive orders from state governments continue to drive some of the important decisions of generation companies, which may be contrary to cost-minimization objectives.

Bacon and Besant-Jones (2001) emphasize that separating generation from transmission and distribution is likely to be most successful when it is accompanied by tariff reform and when it induces competition in generation. Tariff reform that promotes cost recovery in the electricity sector is needed to make generation profitable. Although tariff reform has begun, in 2006 only 3 of the 10 states that had unbundled were making positive profits (The Energy and Resources Institute 2009, Table 1.80). Another way in which unbundling may increase generation efficiency is through increased competitive pressure from the entry of IPPs into the electricity market. Such an effect followed the restructuring of the US electricity sector, but has not yet occurred on a large scale in India.

Tables

Table 1. *Timeline of Reforms*

Unbundling Phase	State	SERC	SEB unbundled
Phase 1	Orissa	1995	1996
	Andhra Pradesh	1999	1998
	Haryana	1998	1998
	Karnataka	1999	1999
	Uttar Pradesh	1999	1999
	Rajasthan	2000	2000
	Delhi	1999	2002
	Madhya Pradesh	1998	2002
Phase 2	Assam	2001	2004
	Maharashtra	1999	2005
	Gujarat	1998	2006
	West Bengal	1999	2007
	Chhattisgarh	2000	2008
	Punjab	1999	2010
	Tamil Nadu	1999	2010
	Bihar	2005	[a]
	Jharkhand	2003	[a]

[a] Reform not implemented by 2012. **Note:** Phase 2 of reforms took place after the Electricity Act of 2003.

Table 2A. *Variable Means, State-owned EGUs, by Unbundling Phase (EGU Data)*

	Phase-I		Phase-II		Phase-III			
	1988 - 1995		1988 - 1995		1988 - 1995			
	Mean	Std. dev.	Mean	Std. dev.	Mean	Std. dev.	Diff. in means	
	[1]	[2]	[3]	[4]	[5]	[6]	[1]-[3]	[1]-[5]
Nameplate capacity (MW)	117	73	146	74	131	60	-29***	-14***
Generation (GWh)	534	489	686	498	561	465	-152***	-27
Age (yrs.)	14.8	8.0	13.5	8.2	12.9	7.5	1.3**	1.8***
Forced outages (%)	21.5	20.4	16.8	20.4	17.6	17.2	4.6***	3.9**
Planned maintenance (%)	12.2	18.7	14.2	18.7	18.3	27.4	-2	-6.1***
Availability (%)	66.3	23.4	69.0	23.8	64.1	26.4	-2.6*	2.2
Capacity utilization (%)	50.0	21.2	49.8	20.7	46.0	24.0	0.2	3.9**
	2006 - 2009		2006 - 2009		2006 - 2009			
Nameplate capacity (MW)	164	91	172	86	159	61	-8	4
Generation (GWh)	1062	750	1052	656	1038	664	10	24
Age (yrs.)	23.0	12.2	24.6	11.7	24.7	9.3	-1.6*	-1.7*
Forced outages (%)	10.8	14.7	12.6	16.3	13.3	18.4	-1.8	-2.5
Planned maintenance (%)	8.2	15.6	6.1	9.8	12.6	23.1	2.1**	-4.4**
Availability (%)	81.0	19.8	81.4	18.0	74.2	27.6	-0.3	6.9***
Capacity utilization (%)	69.1	23.7	68.1	20.1	66.1	30.0	1	3

Notes: Phase 1 (pre-2003): Andhra Pradesh, Haryana, Karnataka, Orissa, Rajasthan, Uttar Pradesh, Delhi, and Madhya Pradesh. Phase 2 (post-2003): Gujarat, Maharashtra, West Bengal, Chhattisgarh and Assam. Phase 3 (out-of-sample): Bihar, Punjab, Tamil Nadu and Jharkhand. GWh, gigawatt-hours; MW, megawatts. 1988-1995 does not contain data for 1992 and 1993. Difference in means according to a two-sample *t*-test with unequal variances*** $p<0.01$, ** $p<0.05$, * $p<0.1$. Number of observations (1988-1995): Phase 1- 466, Phase 2- 461, Phase 3- 217. Number of observations (2006-2009): Phase 1- 399, Phase 2- 370, Phase 3- 155.

Table 2B. *Variable Means, State-owned EGUs, by Unbundling Phase (Plant Data)*

	Phase-I			Phase-II			Phase-III				
	1988-1995			1988-1995			1988-1995				
	Obs.	Mean	Std. Dev.	Obs.	Mean	Std. Dev.	Obs.	Mean	Std. Dev.	Diff. in means	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[2]-[5]	[2]-[8]
No. of operating units	117	3.98	3.03	118	3.91	1.67	50	4.34	2.41	0.08	-0.36
Nameplate capacity (MW)	115	473	421	117	574	383	49	580	285	-100*	-107*
Heating value of coal (kcal/kg)	58	4203	617	67	4307	604	32	3809	380	-104	394***
Design heat rate (kcal/kWh)	36	2633	194	41	2438	148	12	2486	70	195***	147***
Operating heat rate (kcal/kWh)	59	3478	950	69	3135	537	32	3210	664	342**	268
Specific coal cons. (kg/kWh)	98	0.83	0.15	103	0.72	0.12	49	0.82	0.13	0.11***	0.01
	2006-2009			2006-2009			2006-2009				
No. of operating units	86	4.64	2.76	93	3.98	1.90	44	3.52	1.73	0.66*	1.12***
Nameplate capacity (MW)	86	760	551	93	685	509	44	561	347	74.4	199**
Heating value of coal (kcal/kg)	48	3547	386	45	3673	493	29	3773	334	-125	-226***
Design heat rate (kcal/kWh)	53	2405	177	66	2423	201	29	2383	110	-18.2	21.9
Operating heat rate (kcal/kWh)	53	2901	642	65	2932	323	29	2777	456	-31.9	123
Specific coal cons. (kg/kWh)	76	0.82	0.13	63	0.78	0.09	41	0.78	0.15	0.04**	0.04

Notes: Phase 1 (pre-2003): Andhra Pradesh, Haryana, Karnataka, Orissa, Rajasthan, Uttar Pradesh, Delhi, and Madhya Pradesh. Phase 2 (post-2003): Gujarat, Maharashtra, West Bengal, Chhattisgarh and Assam. Phase 3 (out-of-sample): Bihar, Punjab, Tamil Nadu and Jharkhand. GWh, gigawatt-hours; MW, megawatts; kcal/kWh, kilo-calories/kilowatt-hours. 1988-1995 does not contain data for 1992 and 1993. Difference in means according to a two-sample *t*-test with unequal variances*** $p<0.01$, ** $p<0.05$, * $p<0.1$.

Table 3A. *Variable Means, by Sector (EGU Data)*

	CENTER 1988 - 1995		STATE 1988 - 1995		
	Mean	St Dev	Mean	St Dev	Diff. in means
	[1]	[2]	[3]	[4]	[1]-[3]
Nameplate capacity (MW)	194	132	131	72	62.80***
Generation (GWh)	1046	917	602	493	443.6***
Age (yrs.)	13.5	10.7	13.9	8.0	-0.36
Forced outages (%)	14.9	16.8	18.7	19.7	-3.82***
Planned maintenance (%)	9.4	13.9	14.2	20.7	-4.79***
Availability (%)	75.7	19.9	67.1	24.1	8.623***
Capacity utilization (%)	59.5	21.1	49.2	21.5	10.23***
	2006 - 2009		2006 - 2009		
Nameplate capacity (MW)	259	155	166	85	93.01***
Generation (GWh)	1928	1281	1054	699	873.4***
Age (yrs.)	20.2	12.2	23.9	11.6	-3.72***
Forced outages (%)	5.6	9.6	11.9	16.0	-6.36***
Planned maintenance (%)	5.8	5.5	8.1	15.4	-2.28***
Availability (%)	88.7	10.5	80.0	20.8	8.642***
Capacity utilization (%)	84.7	14.2	68.2	23.6	16.49***

Notes: GWh, gigawatt-hours; MW, megawatts. 1988-1995 does not contain data for 1992 and 1993. Difference in means between State and Central plants according to a two-sample *t*-test with unequal variances*** $p<0.01$, ** $p<0.05$, * $p<0.1$. Number of observations (1988-1995): Center- 404, State-1141. Number of observations (2006-2009): Center- 435, State- 924.

Table 3B. *Variable Means, by Sector (Plant Data)*

	CENTER			STATE			
	1988-1995			1988-1995			
	Obs.	Mean	Std. Dev.	Obs.	Mean	Std. Dev.	Diff. in means
	[1]	[2]	[3]	[4]	[5]	[6]	[2]-[5]
No. of operating units	92	4.39	2.26	285	4.01	2.44	0.38
Nameplate capacity (MW)	90	872	601	281	534	386	338***
Heating value of coal (kcal/kg)	42	4092	543	157	4167	598	-75
Design heat rate (kcal/kWh)	12	2530	164	89	2523	185	6.73
Operating heat rate (kcal/kWh)	43	2984	387	160	3276	751	-293***
Specific coal cons. (kg/kWh)	67	0.73	0.12	250	0.78	0.14	-0.05***
	2006-2009			2006-2009			
No. of operating units	87	5.00	2.17	223	4.14	2.28	0.86***
Nameplate capacity (MW)	87	1297	854	223	689	502	608***
Heating value of coal (kcal/kg)	11	4323	267	122	3647	424	676***
Design heat rate (kcal/kWh)	23	2505	137	148	2409	178	96***
Operating heat rate (kcal/kWh)	23	3138	398	147	2890	486	247**
Specific coal cons. (kg/kWh)	74	0.71	0.07	180	0.80	0.12	-0.08***

Notes: GWh, gigawatt-hours; MW, megawatts; kcal/kWh, kilo-calories/kilowatt-hours. 1988-1995 does not contain data for 1992 and 1993. Difference in means between State and Central plants according to a two-sample *t*-test with unequal variances*** $p<0.01$, ** $p<0.05$, * $p<0.1$.

Table 4: *Thermal Efficiency - Impact of Unbundling on State Plants*

	[1] Log Heat rate	[2] Log Specific Coal Cn.	[3] Log Heat rate	[4] Log Specific Coal Cn.
[Unbundled]	0.0320	0.0356*		
	(0.0201)	(0.0189)		
[Phase-I*Unbundled]			-0.0183	-0.0107
			(0.0229)	(0.0179)
[Phase-II*Unbundled]			0.0820***	0.0818***
			(0.0223)	(0.0207)
ln(Design Heat Rate)	0.491***	0.483***	0.448***	0.444***
	(0.157)	(0.138)	(0.133)	(0.117)
ln(Heating value of Coal)	0.514***	-0.451***	0.508***	-0.457***
	(0.0890)	(0.0869)	(0.0834)	(0.0824)
Average Age	0.00578**	0.00786**	0.00711**	0.00908**
	(0.00261)	(0.00347)	(0.00259)	(0.00339)
Average Age^2	0.000139***	8.20e-05	0.000120**	6.46e-05
	(4.35e-05)	(5.04e-05)	(4.45e-05)	(4.91e-05)
Average Nameplate Capacity	-0.000953	-0.000572	-0.000872	-0.000498
	(0.000698)	(0.000677)	(0.000659)	(0.000644)
Time Trend	State	State	State	State
Plant FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
Observations	478	478	478	478

Notes: Std. errors in parentheses, clustered at state level. *** p<0.01, ** p<0.05, * p<0.1. All equations control for a quadratic for plant age, average capacity, design heat rate, heat content of coal, year and plant fixed effects and state time trends. Number of observations=478 (46 Plants).

Table 5: *Operating Reliability - Impact of Unbundling on State EGUs*

	[1]	[2]	[3]	[4]
	Average Impacts		Heterogeneous Impacts	
	Availability	Forced Outages	Availability	Forced Outages
[Unbundled]	0.743	-1.824		
	(1.885)	(1.352)		
[Phase-I*Unbundled]			6.793**	-5.110***
			(2.819)	(1.726)
[Phase-II*Unbundled]			-5.559*	1.599
			(2.993)	(2.467)
Time Trend	State	State	State	State
Unit FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes

Notes: Std. errors in parentheses, clustered at state level. *** $p<0.01$, ** $p<0.05$, * $p<0.1$. All equations control for a quadratic for EGU age, year and plant fixed effects and state time trends. Number of observations=4298 (270 Units).

Table 6: *Robustness Checks - Impact of Unbundling on State EGUs*

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	Drop Phase 2		**Phase Trends**		**Drop Shutdown**		**Drop Enter/Exit**	
	Availabilit y	Forced Outages	Availabilit y	Forced Outages	Availabilit y	Forced Outages	Availabilit y	Forced Outages
1[Phase-I*Unbundled]$_{it}$	5.983**	-	6.711**	-	4.943*	-	6.141*	-
	(2.512)	(1.447)	(2.870)	(1.740)	(2.359)	(1.421)	(3.163)	(2.047)
1[Phase-			-6.656**	1.754	-5.415*	0.987	-8.501**	1.434
			(3.097)	(2.350)	(2.949)	(2.583)	(3.013)	(2.378)
Time Trend	State	State	Phase	Phase	State	State	State	State
Observations	2,605	2,605	4,298	4,298	3,859	3,859	2,895	2,895
Number of id	166	166	270	270	236	236	147	147

Notes: Standard errors in parentheses clustered at state level**.** *** *p*<0.01, ** *p*<0.05, * *p*<0.1**.** All equations control for a quadratic for EGU age, and EGU and Year fixed effects. Columns [1]-[2] drop Phase 2 states from the estimation sample. Columns [3]-[4], substitute phase-wise trends instead of state-specific trends. Columns [5]-[6] drop units that were decommissioned during the sample period. Columns [9]-[10] drop units that were either commissioned or decommissioned during the sample period.

Table 7: *Triple Difference Estimates (DDD) - Impact of Unbundling on State EGUs*

	[1]	[2]	[3]	[4]	[5]	[6]
			Drop Shutdown		**Drop Enter/Exit**	
	Availability	Forced	Availability	Forced	Availability	Forced
[Phase-I*Unbundled]	5.959*	-4.938**	6.284*	-4.435**	7.398	-5.088**
	(3.12)	(1.818)	(3.175)	(1.709)	(4.500)	(2.203)
[Phase-II*Unbundled]	-3.684	3.104	-3.620	2.711	-4.239	1.679
	(2.233)	(2.447)	(2.285)	(2.419)	(5.589)	(6.400)
Observations	6054	6054	5,541	5,541	4,024	4,024
Number of Units	385	385	344	344	203	203

Notes: Standard errors in parentheses clustered at state level. *** p<0.01, ** p<0.05, * p<0.1. All equations control for a quadratic for EGU age, and a full set of state×year, ownership×year and EGU fixed effects.

Table 8. *Capacity Utilization Factor – Impact of Unbundling on EGUs*

	[1]	[2]
	Capacity Utilization	
	DD	DDD
[Phase-I*Unbundled]	3.955	1.101
	(3.475)	(2.789)
[Phase-II*Unbundled]	-4.039	0.571
	(3.281)	(2.133)
Observations	4,298	6,054
Number of EGUs	270	385

Notes: Std. errors in parentheses, clustered at state level. *** $p<0.01$, ** $p<0.05$, * $p<0.1$.) Estimations in both column [1] and [2], respectively, control for all the same controls as the earlier estimations for DD and DDD.

Table 9: *Operating Reliability by Size of EGU*

	[1]	[2]	[3]
	Dependent Variable		
Interaction Variable	Availability	Forced Outages	Capacity Utilization
Phase-I			
[Phase-I*Unbundled] * Less than 100 MW	4.239	-5.564**	2.141
	(3.265)	(2.168)	(5.033)
[Phase-I*Unbundled] * 110/120 MW	12.26***	-9.313**	9.415**
	(3.041)	(3.518)	(4.214)
[Phase-I*Unbundled] * 200/210 MW	6.466	-2.913	2.812
	(4.279)	(1.748)	(4.049)
[Phase-I*Unbundled] *500 MW	1.169	-0.192	1.716
	(2.178)	(2.224)	(3.057)
Phase-II			
[Phase-II*Unbundled] * Less than 100 MW	-6.098	3.706	1.013
	(4.998)	(4.003)	(4.129)
[Phase-II*Unbundled] * 110/120 MW	-7.492**	2.764	-7.851**
	(3.275)	(4.793)	(3.482)
[Phase-II*Unbundled] * 200/210 MW	-4.396	0.325	-3.514
	(2.565)	(1.487)	(3.366)
[Phase-II*Unbundled] * 500 MW	-10.13***	4.658***	-14.57***
	(2.358)	(1.413)	(2.825)

Notes: Number of observations for all specifications=4298 (270 EGUs). Each column in Panel A and Panel B represents coefficients from a single DD estimation. Less than 100MW: all EGUs <100MW; 110/120MW: between 100MW and <150MW; 200/210/250MW: between 150MW and 300MW; and 500MW: 490 MW and above. All equations control for a quadratic for EGU age, year and EGU fixed effects and state time trends. Standard errors in parenthesis clustered at the state level. **. *** *p*<0.01, ** *p*<0.05, * *p*<0.1.**

Figures

Figure 1. *Trends in Outcome Variables*

Figure 1A. Trend in Availability for State and Center Owned EGUs

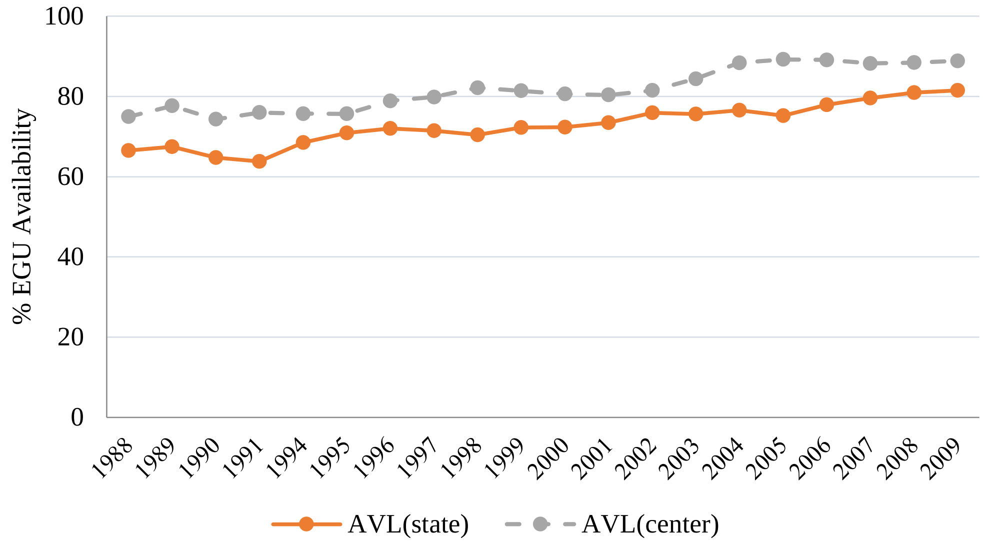


Figure 1B: Trend in Forced Outage for State and Center Owned EGUs

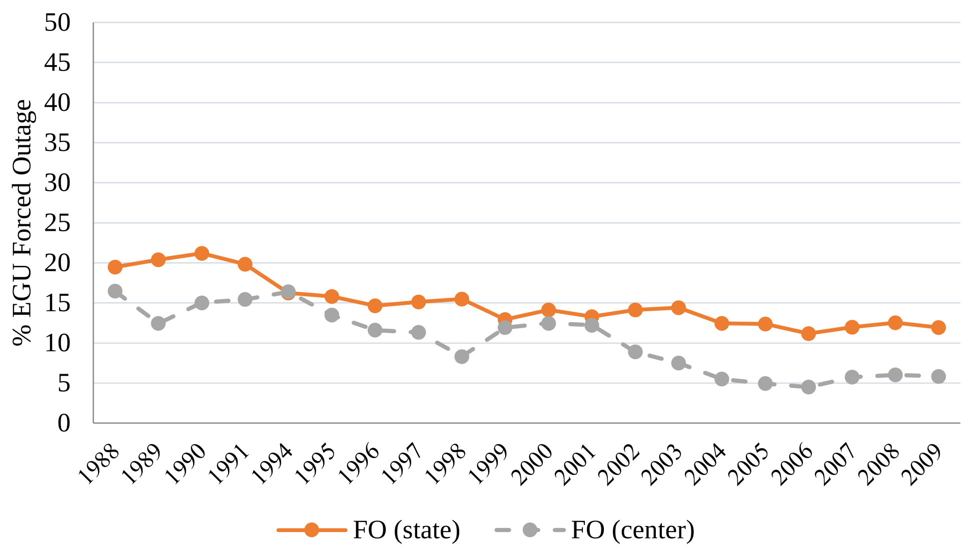


Figure 1C: Trend in Capacity Utilization for State and Center Owned EGUs

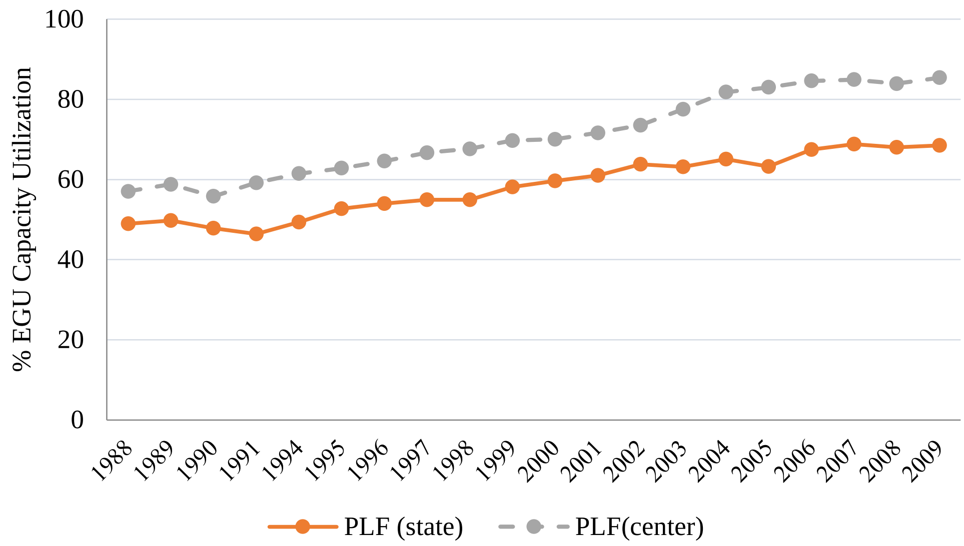
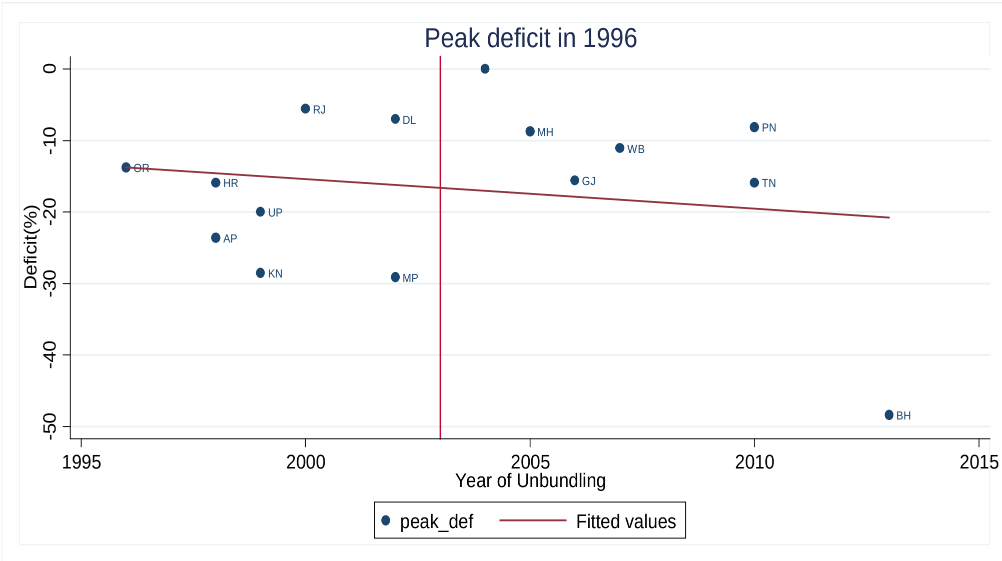
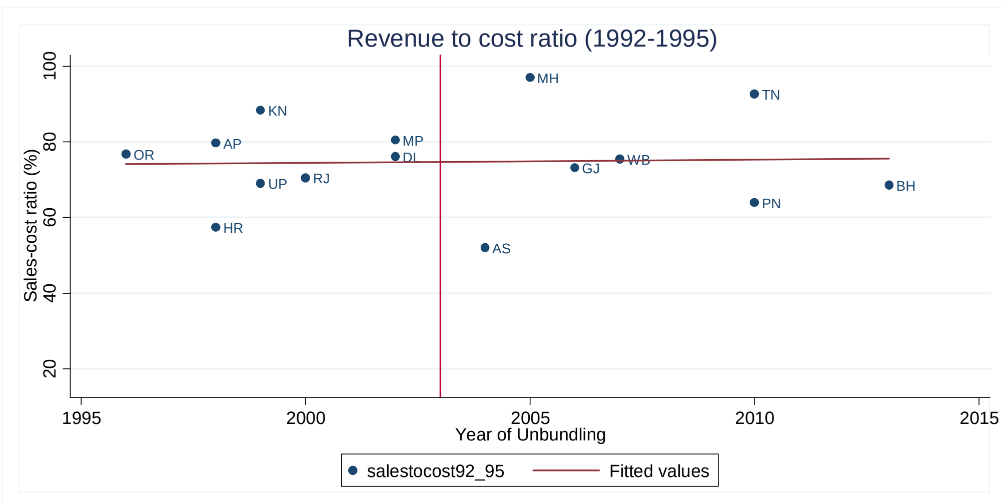


Figure 2: *Correlates of the Year of Unbundling across States*

Panel A: Energy deficit at peak demand in 1996

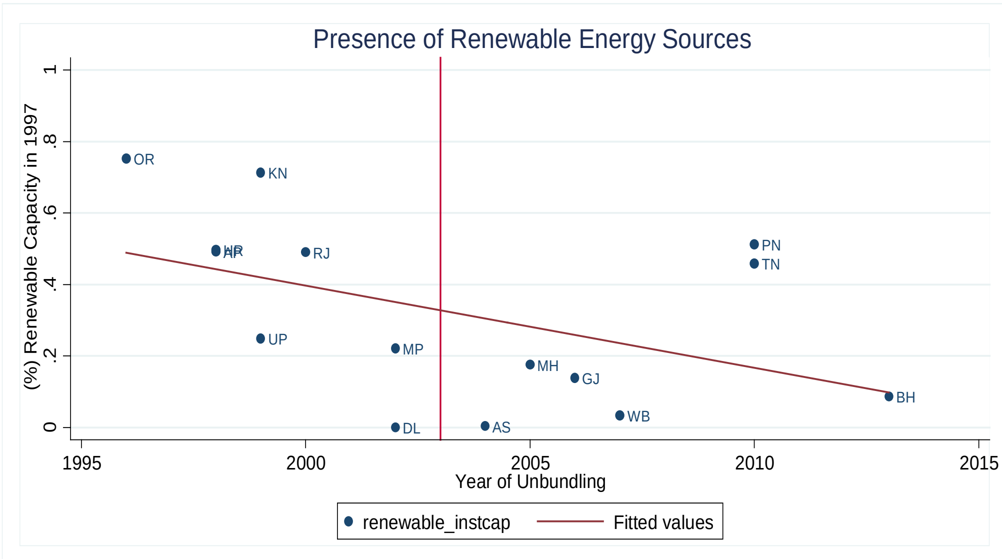


Panel B: Financial well-being of SEB prior to reform

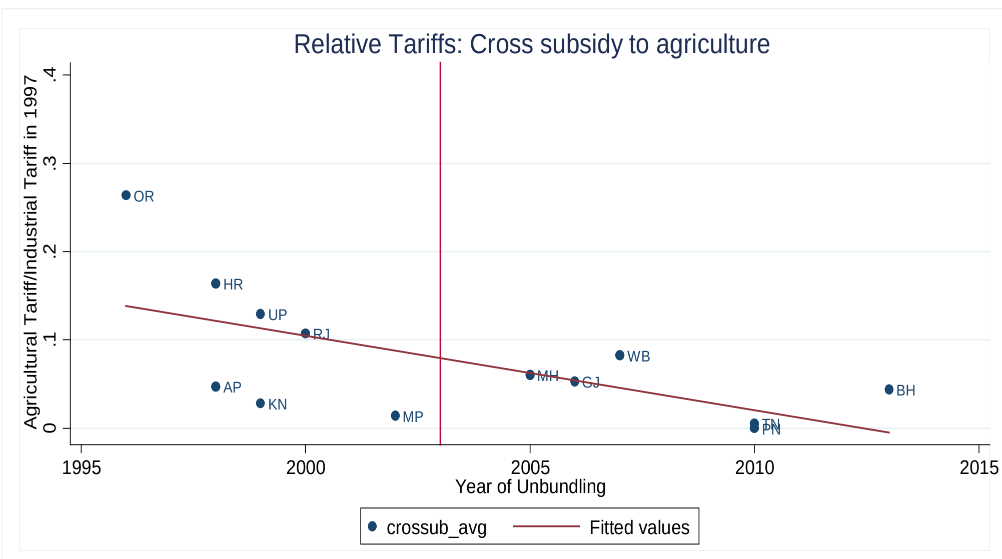


Note: 1. Jharkhand and Bihar have not unbundled as of 2012. I set 2013 as their arbitrary unbundling date to plot the averages. (2) The red line represents the Electricity Act of 2003 which divides the first and second phase of reforms.

Panel C: Renewable energy capacity in 1997(Hydro and Wind)



Panel D: Cross-subsidy to agriculture in 1997



Note: 1. Jharkhand and Bihar have not unbundled as of 2012. I set 2013 as their arbitrary unbundling date to plot the averages. (2) The red line represents the Electricity Act of 2003 which divides the first and second phase of reforms.

Figure 3: *Units Operating in Unbundled State-owned Generation Plants by year*

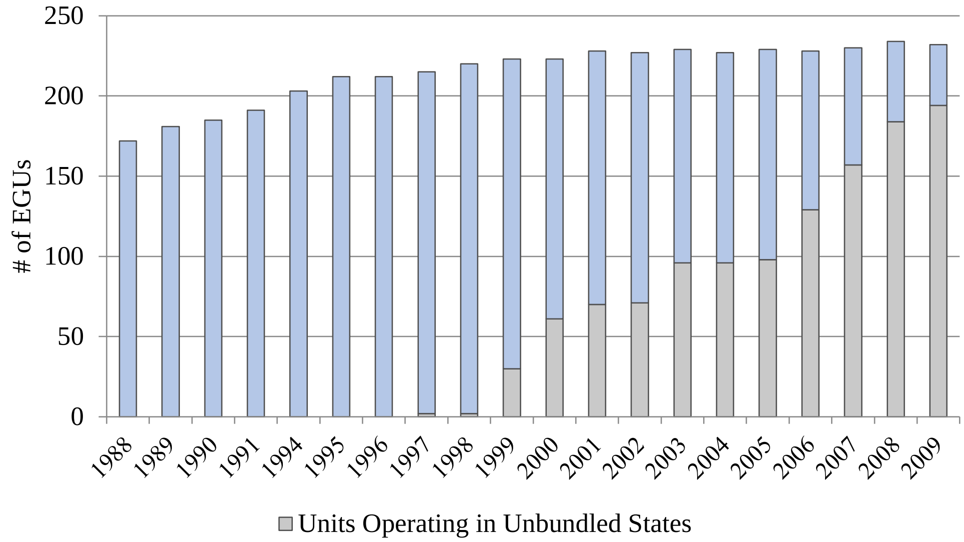


Figure 4: *Duration Effects*

Figure 4A: Post Treatment Flexible Duration Estimates from DD Specification

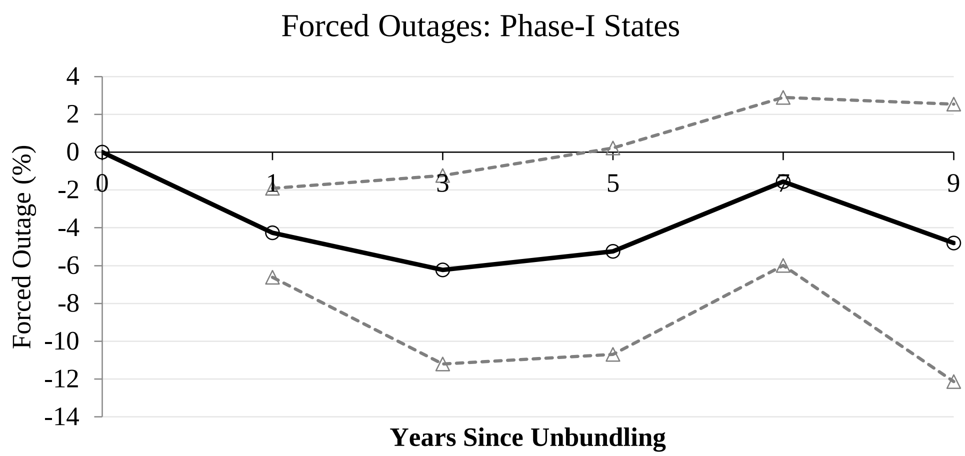


Figure 4B: Post Treatment Flexible Duration Estimates from DDD Specification

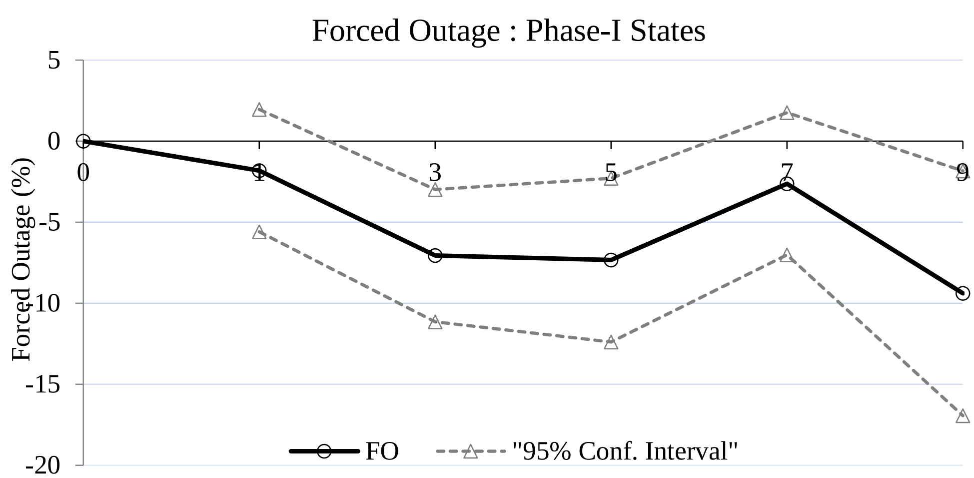


Figure 4C: Pre and Post Treatment Flexible Duration Estimates from DDD Specification

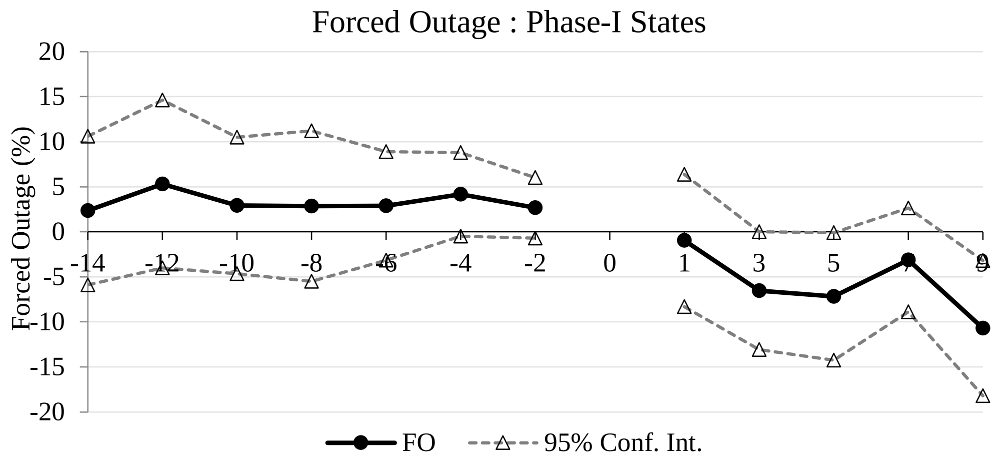
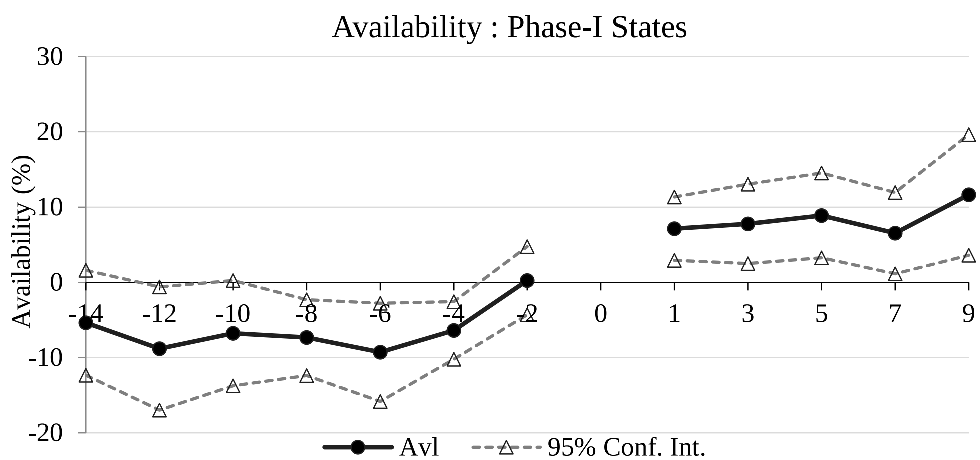


Figure 4D: Pre and Post Treatment Flexible Duration Estimates from DDD Specification



II. Chapter 2

The Health Effects of Coal Electricity Generation in India[32]

1. Introduction

Throughout the world, thermal power plants, in addition to emitting greenhouse gases, are a major source of local pollution and health damages. This is especially true of coal-fired power plants, which generate 41 percent of the world's electricity (IEA 2008). In the United States, after three decades of regulation, coal-fired power plants were estimated to cause between 10,000 (NRC 2010) and 30,000 (Levy et al. 2009) deaths annually, due to emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x) and directly emitted particulate matter (PM).[33] In the United States, the benefits of further reducing emissions from coal-fired power plants have been thoroughly studied (Banzhaf et al. 2004; Levy et al. 2007; Muller and Mendelsohn 2009; USEPA 2005). The purpose of this paper is to shed light on the health benefits of reducing emissions from coal-fired power plants in India, a country where 70 percent of electricity is generated from coal.

The regulation of power plant emissions raises several policy questions: the first is which pollutants should be targeted and how stringently they should be regulated. In the United States, regulation has focused on sulfur dioxide (SO_2) to control fine particles and

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[32] This is based on work jointly authored with Maureen Cropper, Shama Gamkhar, Ian Partridge and Alexander Limonov.

[33] The NAS figure is based on emissions in 2005. Levy et al. (2009) is based on emissions data from 1999. According to NRC (2010), if 2005 emissions data were used by Levy et al., the death figure would be approximately 30,000.

on nitrogen oxides (NO_x) to control fine particles and reduce ground-level ozone. In India, environmental regulations limit particulate emissions, and two states have begun to establish markets to control directly emitted particulate matter.[34] However there are no direct limitations on emissions of SO_2 or NO_x from coal-fired power plants.

An important question is whether more emphasis should be placed on controlling SO_2 and NO_x. The answer to this question depends on the benefits of reducing emissions from these pollutants relative to the costs. To help determine this, I estimate the health damages associated with SO_2, NO_x and directly emitted fine particles ($PM_{2.5}$) from individual power plants in India. My analysis suggests that most deaths attributable to power plants in India are associated with SO_2, followed by NO_x and directly emitted PM. The average number of deaths per plant associated with each pollutant in 2008 was approximately 392 for SO_2, 127 for NO_x and 56 for $PM_{2.5}$. Whether this implies that more emphasis should be placed on controlling SO_2 and NO_x depends on the cost of measures to control these pollutants and upon how effective various measures would be in reducing emissions. Although I do not examine pollution control costs in detail, I provide illustrative calculations that suggest that scrubbers to reduce SO_2 emissions are likely to pass the benefit-cost test at some plants.

A second policy question is what instruments should be used to regulate pollution: should India rely on a cap-and-trade program, as in the United States, or on an emissions tax? If a pollution permit program is used, should permits trade one-for-one, or should they trade at ratios that reflect differences in marginal damages across plants? The answer to

[34] "India to Unveil Emissions Trading Scheme February 1," *The Economic Times*, January 27, 2011.

this question depends on how much the damages per ton of SO_2, NO_x and $PM_{2.5}$ vary across plants. In the United States, Muller and Mendelsohn (2009) argue that the efficiency of SO_2 reduction could be increased significantly by taking differences in marginal damages into account. My analysis suggests that this is not the case for India. In India, the mean number of deaths per thousand tons of SO_2 is 10, and the 5th and 95th percentile are 7 and 11 deaths per thousand tons respectively. (The standard deviation is 2 deaths.)[35] The reason for the small variation in damages per ton in India is that health damages depend heavily on population density: there is much more variation in population density across power plants in the United States than in India.

To estimate the health damages associated with coal-fired power plants I have assembled a database of coal characteristics and usage, electricity generation and emissions for 92 coal-fired power plants for the years 2000–2008. I estimate the health impacts of directly emitted fine particles, sulfates and nitrates based on emissions for the year 2008. To calculate the impact of emissions on ambient air quality, I estimate intake fractions for each category of emissions. An intake fraction measures the change in population-weighted ambient concentrations of a pollutant (e.g., $PM_{2.5}$) per unit of primary pollutant emitted from a pollution source. I estimate intake fractions using equations generated by Zhou et al. (2006) using Chinese data that relate the intake fraction of each pollutant to the population surrounding each power plant and meteorological conditions. Concentration-response functions for fine particles from Pope et al. (2002) are used to estimate premature deaths associated with air emissions.

[35] The range of damages per ton of SO_2 across coal-fired power plants in the United States is much greater, with the standard deviation of damages per ton equal to approximately half the mean (NRC 2010).

After characterizing the distribution of premature mortality across plants I calculate the reduction in mortality and cost-effectiveness of two options to reduce power plant emissions—washing coal to reduce ash content and installing a flue-gas desulfurization unit (scrubber). According to some calculations (Zamuda and Sharpe 2007), coal washing actually pays for itself. I calculate the health benefits and cost-per-life saved of reducing the ash content of coal at the Rihand power plant in Uttar Pradesh. Similar calculations are made for the flue-gas desulfurization unit installed at the Dahanu power plant in Maharashtra.

The paper is organized as follows: The next section presents an overview of the Indian power sector, including a discussion of Indian coal production and the environmental regulations facing power plants. Section 3 describes my database and presents summary statistics on the thermal efficiency of power plants, characteristics of coal consumed and amount and intensity of pollutants emitted, by plant. The impacts of emissions on premature mortality are described in section 4. Section 5 summarizes the policy implications of my findings, and section 6 concludes.

2. Overview of the Indian Power Sector

In 2010, India had approximately 179 gigawatts (GW) of installed electric capacity.[36] Table 1 shows the breakdown of installed capacity by fuel type and region. Coal-fired power plants accounted for 53 percent and natural gas plants for 11 percent of installed capacity; however, thermal power plants accounted for 83 percent of electricity generated (CEA 2010). Figure 1 maps the location of coal-fired capacity by state.

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[36] This represents capacity connected to the grid, including 19,509 MW of captive generation.

Most generating capacity in India is government owned. The 1948 Electricity Supply Act created State Electricity Boards (SEBs) and gave them responsibility for the generation, transmission, and distribution of power, as well as the authority to set tariffs. SEBs operated on soft budgets, with revenue shortfalls made up by state governments. Electricity tariffs set by SEBs failed to cover costs, generating capacity expanded slowly in the 1960s and 1970s, and blackouts were common. To increase generating capacity, the Government of India in 1975 established the National Hydroelectric Power Corporation and the National Thermal Power Corporation, which built generating capacity and transmission lines that fed into the SEB systems. In 1990, 63 percent of installed capacity in the electricity sector in India was owned by SEBs, 33 percent by the central government, and 4 percent by private companies (Tongia 2003).

In 1991, legislation was passed to encourage independent power producers (IPPs) to enter the electricity market, in accordance with the government's broader macroeconomic liberalization and privatization agenda. The Electricity Acts of 1998 and 2003 led to the creation of a Central Electricity Regulatory Commission (CERC) and similar regulatory bodies at the state level (the SERCs). The Acts also paved the way for the unbundling of generation, transmission, and distribution functions; the privatization of distribution companies; and the restructuring of the electricity tariff structure. Currently, private companies (including IPPs) own 14 percent of generation capacity in India; however, they own a smaller share (9 percent) of coal-fired generation capacity. Thirty-eight percent of coal-fired capacity is owned by the central government and 53 percent is state owned (CEA 2010).

2.1 Plant Thermal Efficiency and Coal Quality

Coal-fired power plants in India are, in general, less efficient than their counterparts in the United States. Thermal efficiency is typically measured by the net output of an electricity generating unit expressed as percent of the heat input used (net thermal efficiency), or by operating heat rate—the heat input (in kcal) required to produce a kWh of electricity. The average net efficiency of coal-fired power plants in India is currently below 28 percent (see Table 5). In 2008, the U.S. coal-fired power plant fleet had a generation-weighted average efficiency of 32.5 percent, while the top 10 percent of the fleet had an efficiency of 37.6 percent, five percentage points higher (DOE 2010). The average operating heat rate of the coal-fired power plants in my database in 2008 (see Table 5) is 2,856 kcal/kWh, which is 20 percent higher than the average operating heat rate of subcritical plants in the United States during the period 1960–1980 (Joskow and Schmalensee 1987).

The higher average operating heat rates of Indian plants are due in part to the poor quality of Indian coal but also to inefficiencies in management. The design heat rate of generating units that use coal with high moisture and/or high ash content is higher than for units with low moisture and ash content (MIT 2007). The ash content of Indian coal is between 30 and 50 percent. This implies that Indian plants will require more energy to produce a kWh of electricity than comparable plants in the United States. The operating heat rate of the plant—the actual number of kcal of thermal energy required to produce a kWh—may be higher than the design heat rate if the plant is poorly maintained or experiences frequent outages.[37] For the 50 coal-fired power plants for which I have data in 2008, operating heat rates are, on average, 18 percent higher than design heat rates. Privately owned plants have, on average, lower operating heat rates and smaller deviations of operating from design heat rates than do state-owned plants.

Indian coal also has much lower heating value than coal mined in the United States or China. One consequence of the low heating value of Indian coal is that, ceteris paribus, more coal is used to produce a kWh of electricity in India than in other countries. The coal consumption per kWh of electricity (in kg/kWh) equals, by definition, a plant's operating heat rate (kcal/kWh) divided by the heating value of its coal (kcal/kg). Ninety percent of the coal used to generate electricity in India is domestic coal with a heating value between 2,700 and 4,400 kcal/kg.[38] The heating value of coal mined in the eastern United States is between 6,000 and 7,300 kcal/kg (MIT 2007). It is lower in the western United States (4,600–4,700 kcal/kg) and slightly higher in China (4,600–6,000 kcal/kg) (MIT, 2007). The end result of higher operating heat rates and the use of coal with lower heating value is that approximately 770 grams of coal are burned to produce one kWh of electricity in India, in contrast to values half as large in the United States and China.[39]

The pollution intensity of Indian power plants (i.e., grams of pollutant per kWh) also depends on the ash and sulfur content of the coal burned. Indian coal has high ash content, between 35 and 50 percent by weight, and lower sulfur content: about 0.5 percent

[37] Whenever a plant is started up after an outage, more coal is burned than during the normal operation of the plant.
[38] This is the range of values reported in my database for 2008. *The Future of Coal* (MIT 2007) reports a range of 3,000–5,000 kcal/kg for Indian coal.
[39] A study by Ohio State University reports 360 g/kWh for Ohio coal, with a heating value of 6,378 kcal/kg. A study quoted by the World Resources Institute (WRI) reports 345 g/kWh in China.

by weight. Based on data from the late 1990s , Garg et al. (2002) report a consumption-weighted ash content of 45 percent; Reddy and Venkataraman (2002) report a consumption-weighted ash content of 39 percent. The corresponding figures for sulfur are 0.51 percent (Garg et al. 2002) and 0.59 percent (Reddy and Venkataraman 2002). Information on the distribution of ash and sulfur across individual plants is more difficult to obtain. A chemical analysis of coal at five Indian plants in 1998 by researchers at Ohio State University (Ohio Supercomputer Center) revealed a range of ash contents from 26 to 47 percent (with an average of 39 percent) and sulfur contents from 0.33 to 0.8 percent (average 0.48 percent). To put these numbers in perspective, the ash content of eastern U.S. coal in the same year ranged from 7.5 to 20 percent, and the sulfur content from 1.0 to 2.5 percent.[40]

The high ash content of Indian coal may lead to high PM emissions. Although all coal plants in India have electrostatic precipitators (ESPs), the high ash content of coal and its chemical composition reduce their removal efficiency (CPCB 2007). There is also the problem of fly ash disposal. Approximately 100 million tons of fly ash is generated annually. The ash is stored in ponds and poses a hazard to surface water sources from runoff and to ground water from percolation. My analysis does not quantify the health costs associated with fly ash disposal.

[40] Reliance on coal from the Appalachian and Illinois basins in the United States has declined over time. Currently, 30 percent of coal comes from the Powder River Basin in southeastern Montana and northeastern Wyoming. PRB coal has a sulfur content below 0.5 percent, and a lower ash (and heat) content than coal mined in the eastern US (MIT 2007).

2.2 Environmental Regulations Affecting Air Emissions

In India, the primary responsibility for issuing and enforcing environmental regulations lies with the State and Central Pollution Control Boards, which fall under the State and Central Ministries of Environment and Forests (MoEF) (Chikkatur 2008). The current federal ambient air quality standards for particulates, SO_2, NO_x and ozone are listed in Table 2. The State and Central Pollution Control Boards are responsible for achieving ambient standards, but implementation plans similar to those in the United States are required only for 24 "critically polluted" areas and 17 cities (Narain 2008).

The CPCB issues emissions regulations for highly polluting industries, including power plants.[41] Particulate emissions are affected indirectly by coal washing requirements and directly by emission limits (see Table 3). Beginning in 2002, the use of coal with ash content exceeding 34 percent was prohibited in any thermal power plant located more than 1,000 km from the pithead or in urban or sensitive or critically polluted areas. At the time the regulation was issued, it was estimated to affect approximately 24 GW of installed capacity.[42] In practice, the standard is achieved by blending washed and unwashed coal (or imported coal) to reduce average ash content to 34 percent. Zamuda and Sharpe (2007) estimate that in 2005-2006, only 5 percent of domestic coal used in power plants was washed. They also note that beneficiation plants were operating at only 44 percent of capacity.

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[41] I focus in this section on regulations that affect air emissions. Thermal power plants are also subject to Environmental Impact Assessments before they are built and must meet standards for the discharge of water used for cooling and for disposal of fly ash (http://www.cpcb.nic.in/divisionsofheadoffice/pci2/ThermalpowerPlants.pdf).

[42] See http://www.cpcb.nic.in/divisionsofheadoffice/pci2/ThermalpowerPlants.pdf.

The emission limits for total suspended particulates listed in Table 3 are concentration limits. Historically, they have been violated by a significant fraction of plants: in 2000–2001, 63 percent of plants did not comply with these standards; in 2006-07, 28 percent of plants failed to comply (Chikkatur and Sagar 2007).

There are no emission limits for sulfur dioxide or for nitrogen oxides for coal-fired power plants.[43] SO_2 concentrations are affected primarily by minimum stack height requirements and the requirement that electricity generating units of 500 MW or more leave space for a flue-gas desulfurization (FGD) unit (see Table 4). Generating units between 210 and 500 MW must have stacks of at least 220 meters; units greater than 500 MW must have stacks at least 275 meters in height. Currently there are 3 plants in India that have installed flue-gas desulfurization units—Dahanu (Maharashtra), Trombay (Maharashtra) and Udupi (Karnataka).

3. Emissions and Emissions Intensity of Existing Plants

To examine the air pollution impacts of coal-fired power plants, I have constructed a dataset on the operating characteristics of all coal-fired plants that report to the Central Electricity Authority of India (CEA).[44] The result is an unbalanced panel of 92 thermal power plants, located in 17 states, for the years 2000–2008.[45] My analysis focuses on the

[43] Officials at the Central Electricity Authority report that most plants have low-NO_x burners, although this is not required by law (CEA personal communication 2011).
[44] The CEA annually publishes the Thermal Power Review, which describes the operating characteristics of all state- operated thermal power plants in India and provides some data on central government and privately-owned plants.
[45] All years in my dataset are Indian fiscal years. Thus 2000 refers to the time period April 1, 2000 through March 30, 2001. My data on emissions begin in 2000. Data on plant characteristics are available beginning in 1988 (see Chapter 1).

year 2008.[46] In that year I have 57 state owned, 22 central government owned and 13 privately owned plants, which constituted 88 percent of the total installed coal-fired generation capacity in the country.

Table 5 presents summary statistics on operating characteristics of plants, for all plants and for plants by type of ownership.[47] The table underscores the points made above regarding the thermal efficiency of coal-fired power plants and Indian coal: net thermal efficiency, averaged across all plants, is 27.7 percent. The average heating value of coal is approximately 3,625 kcal/kg; and, on average, 770 grams of coal are burned to produce one kWh of electricity. A comparison of operating heat rates and heating value of coal by ownership status is difficult, as data are often missing for privately owned plants and for plants operated by the National Thermal Power Corporation (NTPC). The table does, however, suggest that state owned plants consume significantly more coal per kWh than do private and central government plants.

The CEA reports total suspended particulate (SPM) concentrations, measured in mg per normal cubic meter of flue gases (mg/Nm^3) in its annual thermal power sector reports. Concentrations for each plant are reported as a range. Table 6 reports summary statistics for the upper and lower ends of this range, as well as the midpoint of the range, for 2008. The midpoint of the emissions range is below the 150 mg/Nm^3 standard for three-quarters of the 74 plants for which data are available. Data are not randomly missing: they are missing for 62 percent of private plants, 23 percent of state plants and 14 percent of

[46] All information in Tables 5–8 is based on the year 2008. Calculations based on averages for the period 2006–2008 produced very similar results.
[47] Central plants are plants operated by the central government, including National Thermal Power Corporation (NTPC) plants.

central government owned plants. Subject to these caveats, it is clear that emission concentrations are, on average, lowest at privately owned plants, and lower at central government owned plants than they are at state owned plants. The difference in concentration rates between state and centrally owned plants disappears, however, once the vintage of generating equipment and the heating value of coal are held constant.

A simple regression of the logarithm of the midpoint of SPM concentrations in flue gas on the average age of generating equipment, average age squared, heating value of coal and ownership dummies explains 51 percent of the variation in concentration rates. Concentration rates are lower the higher the heating value of coal and increase (at a decreasing rate) with the vintage of generating equipment. Evaluated at mean plant age, a one year increase in the age of electrical generating unit (EGU) raises particulate concentrations by about 3.5 percent. An increase in the heating value of coal by 1,000 kcal/kg is associated with a 0.25 percent reduction in SPM concentrations. Concentrations are significantly lower at private plants than at state plants, but there is no statistically significant difference between state and centrally owned plants when age and heating value are held constant.

Table 6 also presents summary statistics on annual tons of particulate matter, SO_2 and NO_x emitted, as well as on the emissions intensity (in kg of pollutant per MWh) of these pollutants.[48] To convert SPM concentration rates into tons of SPM emitted per year requires data on annual coal usage as well as assumptions about the volume of flue gases

[48] SO_2 and NO_x emissions data are missing for plants for which coal consumption data are missing. $PM_{2.5}$ emissions data are missing if either coal consumption data or SPM data are missing.

per ton of coal burned[49]. Results are presented for emissions of $PM_{2.5}$, assuming a ratio of $PM_{2.5}$/SPM of 0.8. Calculating sulfur emissions requires data on the sulfur content of coal as well as on coal consumption. The data on coal quality is derived from a survey of 9 individual power plants, all owned by NTPC in various parts of the country. The average coal characteristics derived from this survey are used as the average of all other plants. The average sulfur content assumed is approximately 0.5%. My calculations of NO_x emissions assume that all units commissioned after 1996 are installed with low-NO_x burners. Thus, I assume a 200 ppm NO_x concentration in flue gases for plants fitted with low-NO_x burners and 300 ppm for all other plants.

The quantity of pollutants a plant emits each year reflects the total electricity generated by that plant, the amount of coal it uses per kWh, and its emissions per ton of coal burned. Pollution intensity (i.e. quantity of pollutant per kWh generated) reflects kg of coal per kWh and emissions per ton of coal burned. For all three pollutants, pollution intensity is lower at private than at state or central government owned plants. The pollution intensity of SO_2 emissions is, on average, higher at Indian than at U.S. coal-fired power plants, in spite of the low sulfur content of Indian coal. The median SO_2 pollution intensity at U.S. plants in 2005 was 8.9 pounds per MWh; the mean was 12.3 pounds per MWh (NRC 2010): at Indian plants, (see Table 6) the median SO_2 intensity is 13.4 pounds per MWh; the mean is 15.1 pounds per MWh. This reflects the smaller amount of coal burned per MWh in the United States and the fact that over one-quarter of U.S. coal-fired plants have scrubbers. The average pollution intensity of NO_x emissions is

[49] The calculations are described in detail in Appendix B.

also higher at the plants in my database than at plants in the United States. On average, NO_x intensity at U.S. plants in 2005 was 4.10 pounds per MWh, compared with 4.6 pounds per MWh for Indian plants (see Table 6).

4. Health Damages from Coal-Fired Power Plants

Measuring the health effects of air pollution emissions requires estimating the impact of emissions on ambient air quality and using dose-response functions to relate population-weighted changes in concentrations to health endpoints. I estimate intake fractions—the change in population-weighted ambient concentrations of a pollutant—for directly emitted particles and for secondary sulfates and nitrates using relationships established by Zhou et al. (2006) for China. The resulting changes in population-weighted ambient concentrations are translated into premature deaths using Pope et al. (2002).

4.1 The Intake Fraction Approach to Estimating Health Damages

An intake fraction measures the change in population-weighted ambient concentrations of a pollutant (e.g., $PM_{2.5}$) per unit of primary pollutant emitted from a pollution source. For example, if Q is emissions of $PM_{2.5}$ from a power plant in grams per second, ΔC_i is the change in ambient $PM_{2.5}$ in grid cell i resulting from Q, P_i is the population of the grid cell and BR is the average breathing rate, then the intake fraction is defined as:

(1) $$IF = [\sum_i P_i \Delta C_i BR] / Q ,$$

where the sum in (1) is taken over all grid cells for which ΔC_i is greater than 0.[50] If the average annual intake fraction for $PM_{2.5}$ for a power plant were $1x10^{-5}$, this would mean that for every metric ton of $PM_{2.5}$ emitted by the plant, 10 grams are inhaled by the exposed population.

The IF corresponding to an air pollution source depends on the distribution of population around the source, on meteorological conditions, and on characteristics of the source that affect $\{\Delta C_i/Q\}$. For power plants, source characteristics include stack height, stack diameter and exit velocity. Meteorological conditions include wind speed and direction, temperature, and the concentration of ammonia in the atmosphere.

Rather than modeling intake fractions by running an atmospheric dispersion model for each power plant, I estimate intake fractions using the results of Zhou et al. (2006). Zhou et al. (2006) use a Lagrangian plume model (CALPUFF) to estimate the impact of an 800 MW coal-fired power plant with fixed design characteristics on air quality (i.e., $\{\Delta C_i\}$) in 29 locations in China. IFs are calculated for PM_1, PM_3, PM_7, PM_{13}, SO_2, ammonium sulfate, and ammonium nitrate. For each pollutant, the authors regress the annual average intake fraction on the population in concentric annuli around each plant and on annual precipitation at the plant (in mm/year). The R^2s range from 0.96 (for PM_1) to 0.89 (for PM_{13}). (See Table A2 of the Appendix.) I use these equations to predict intake fractions for Indian power plants. (Details of this transfer are described in the Appendix.)

[50] In Zhou et al. (2006) the average breathing rate is 20 m^3 per day.

The validity of these transfers depends on the similarity between the characteristics of the plant in Zhou et al. (2006) and Indian power plants.[51] Zhou et al. (2006) use a plant with two stacks of 4 and 7 meters in diameter and 210 meters in height. Because damages per ton of pollutant generally decrease with stack height (Muller and Mendelsohn 2007), this will tend to overstate the impacts of power plants with taller stacks and underestimate the impacts of power plants with shorter stacks. Zhou et al. (2006) estimate the impact of the plant on ambient air quality using a modeling domain 3,360 km by 3,360 km. I examine the impact of each power plant in my database on an area that includes India, Pakistan, Bangladesh and Sri Lanka.

Once the intake fraction has been estimated for a particular source and pollutant, it can be used to calculate health impacts. Rearranging equation (1), the population-weighted average change in ambient concentrations, $\sum_i P_i \Delta C_i$, is given by

(2) $$IF * Q / BR = \sum_i P_i \Delta C_i .$$

Thus, once IF has been calculated and annual emissions (Q) are known, $\sum_i P_i \Delta C_i$ can be calculated. In most epidemiological studies of the health effects of air pollution, the relative risk (*RR*) of death or illness associated with a change in pollutant concentration is given by

(3) $$RR = \exp(\beta \sum_i \overline{P_i} \Delta C_i),$$

[51] It also depends on similarity in meteorological conditions such as wind speed and direction, which are more difficult to compare.

where β is estimated from an epidemiological study and $\overline{P_i}$ is the population, as a fraction of the total exposed population, that is in cell *i*. The associated number of cases (*E*) of premature mortality or illness is given by

$$(4) \qquad E = ((RR-1)/RR) * BaseCases,$$

implying that *(RR-1)/RR* is the fraction of existing cases attributable to the source.

4.2 Application of the Intake Fraction Approach to Indian Power Plants

I calculate premature mortality associated with the emissions from each power plant, compared to no emissions, using cardiopulmonary mortality coefficients from Pope et al. (2002). Because Pope et al. (2002) relate premature mortality to $PM_{2.5}$, I convert estimates of SPM to $PM_{2.5}$ assuming a ratio of $PM_{2.5}$ to SPM of 0.8 (USEPA AP-42). I use SO_2 and NO_x emissions for each power plant to estimate the contribution of the plant to sulfates and nitrates, which I add to directly emitted $PM_{2.5}$.[52]

4.2.1 Choice of Concentration-Response Function

The effects of air pollution on human health include the chronic effects of long-term exposure and the acute effects of short-term exposure. In the past two decades, a large number of studies—especially short-term, time-series studies—have reported concentration-response relationships between air pollution exposure and premature mortality. Long-term cohort studies provide the best method of evaluating the chronic effects of air pollution on human health, whereas time-series studies are appropriate for

[52] I do not consider the health impacts form ground level ozone in this analysis. Though studies in the US and Europe have established a link between ground level ozone and premature mortality from cardiovascular diseases, the impact is much smaller compared to that from PM2.5 (EPA, 2011).

revealing the acute effects of short-term fluctuations in pollution levels. Concentration-response coefficients from cohort studies of premature mortality are typically several times higher than coefficients reported in time-series studies. It is assumed that the short-term effects found in time-series studies are embedded in the long-term effects on mortality rates derived from cohort studies.

As of this writing, only a few time-series studies relating air pollution to mortality have been conducted in India (Cropper et al. 1997; Health Effects Institute 2011). The most recent studies—in Ludhiana, Delhi, and Chennai—are part of the Health Effects Institute's Public Health and Air Pollution in Asia (PAPA) program. These studies find similar impacts of PM_{10} on daily mortality as time-series studies conducted in the United States (the NMMAPS (National Morbidity, Mortality, and Air Pollution Study)) and Europe (the APHEA project) (HEI 2011). There are, however, no studies that capture the effects of long-term exposure to particulate matter on mortality in India. Thus I must rely on concentration-response transfer.

The prospective cohort study by Pope et al. (2002) added measurements of air pollution levels (fine particles in 50 cities and sulfates in 151 cities) to data on approximately 500,000 individuals in a prospective cohort assembled by the American Cancer Society. The study, which followed adults aged 30 and over, relates all-cause, cardiopulmonary and lung cancer mortality to annual average $PM_{2.5}$ using a Cox proportional hazard model. Separate coefficients are reported for exposures in 1979–1983 and 1999–2000.

Transferring all-cause mortality coefficients from Pope et al. (2002) to my study region (India, Pakistan, Sri Lanka and Bangladesh) may be inappropriate for two reasons: the levels of $PM_{2.5}$ in the region are higher than in the United States, and the distribution of deaths by cause in the United States differs from the distribution in India and its neighboring countries. One way to deal with the former problem is to use the Pope et al. (2002) coefficients based on air pollution readings in the United States in the 1979–1983 period, when average air pollution levels were higher than in the years 1999–2000. My analysis is based on the former coefficients. The similarity of results in time-series studies across cities with very different pollution readings also lends credence to my analysis. The second problem is handled by transferring impacts from Pope et al. (2002) by cause of death. The primary impact of air pollution on mortality occurs through cardiopulmonary mortality (ICD-9 codes 401–440 and 460–519). In the United States in 2007, 42.5 percent of all deaths over the age of 30 were due to cardiopulmonary causes (CDC 2011); the comparable figure for India in 2004 was 41.7 percent (Indiastat). I proceed with dose-response transfer, based on the cardiopulmonary dose-response coefficient from Pope et al. (2002).[53,54]

In interpreting the results, several points should be kept in mind: the Pope et al. (2002) study applies only to adults 30 years of age and older. My estimates therefore do not capture the impact of air pollution on child deaths.[55] I also ignore the impact of air pollution on morbidity. In this sense, my estimates represent lower bounds to health effects.

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[53] Pope et al. (2002) also find a significant impact of $PM_{2.5}$ on lung cancer deaths. Lung cancer accounts for less than one percent of deaths over age 30 in India (Indiastat); hence I ignore this endpoint.
[54] The details on how the calculation for number of deaths attributable to each power plant are given in section A4 of Appendix B.
[55] Deaths occurring under the age of 30 constitute 28.8 percent of deaths in India.

At the same time, I calculate the impact of air pollution on premature mortality in India, Pakistan, Bangladesh and Sri Lanka. Approximately 16 percent of the deaths reported below occur outside of India.

4.2.2 Estimated Deaths Due to Air Pollution from Coal-Fired Power Plants

Table 7 presents summary statistics for the distribution of deaths attributable to directly emitted $PM_{2.5}$, SO_2 and NO_x from the power plants for which emissions data are available. The average number of deaths associated with current emissions levels, compared to zero emissions, is approximately 581 per plant per year: approximately 392 deaths are associated with SO_2, 127 with NO_x and 56 with $PM_{2.5}$. The table also presents information on the damages per ton of pollutant, which can be calculated for all plants. Damages per ton are, on average, greater for directly emitted $PM_{2.5}$ than for SO_2 or NO_x. There are, on average, 23 deaths per 1,000 tons of $PM_{2.5}$, 10 deaths per 1,000 tons of SO_2, and 9 deaths per 1,000 tons of NO_x.

Two results from Table 7 deserve emphasis: the first is that more deaths are attributable to SO_2 emissions than to either directly emitted particulates or NO_x. Although SO_2 is associated with fewer deaths per ton than $PM_{2.5}$, plants emit many more tons of SO_2 than they do of $PM_{2.5}$. (Recall that all plants use electrostatic precipitators.) NO_x is also associated with more deaths than $PM_{2.5}$ for the same reason. This suggests that more emphasis be placed on policies to control SO_2. The second is that the variation in deaths per ton of pollutant across plants is small: deaths per 1,000 tons of $PM_{2.5}$ range from 15 (5^{th} percentile) to 29 (95^{th} percentile). For SO_2, they range from 7 (5^{th} percentile) to 12 (95^{th} percentile). This variation is due solely to differences in plant location and variation in the size of the population surrounding each plant. Because I count populations 1,000 (and more) km from a plant—whether people live in India or elsewhere—differences in exposed populations across plants are not as great as in the United States.

Table 8 shows deaths associated with air pollution broken down by plant ownership. While there are few differences in mean deaths per ton of pollution among state, center and private plants, there are significant differences in deaths per GWh. These reflect differences in pollution intensity across plants: private plants use, on average, less coal to produce a kWh of electricity and in the case of particulate emissions, they emit less pollution (on average) per ton of coal burned than do state- or center-owned plants.

5. Policy Implications

My analysis of health damages associated with power plants can be used to evaluate the benefits of specific pollution control options. To illustrate how it can be used, I calculate the benefits of two pollution abatement strategies that are not currently in widespread use in India: coal washing and installation of a flue-gas desulfurization unit (FGD). Although thermal power plants located more than 1,000 km from the pithead or in urban or sensitive or critically polluted areas are required to use coal containing no more than 34 percent ash content (CEA 2010), only 5 percent of non-coking coal is washed (Zamuda and Sharpe 2007). I analyze the costs and benefits of using washed coal at the Rihand plant in Uttar Pradesh. I also calculate the benefits of installing a flue-gas desulfurization unit at the Dahanu power plant in Maharashtra (the only plant to have installed a scrubber) and calculate the cost per premature death avoided.

5.1 Health Benefits and Costs of Using Washed Coal

Mined coal contains unwanted mineral content. This mineral content reduces both the combustion efficiency of coal and increases the production of ash as a byproduct of combustion. Coal washing is a method commonly used to clean the coal of its unwanted mineral content before it reaches the power plant.[56] Coal washing generally uses physical processes based on density or gravity separation. The coal, along with its impurities, is crushed and added into a liquid medium. The coal is then separated from the mineral content by subjecting the mixture to either gravity or centrifugal forces.

Coal washing reduces the ash content of coal and improves its heating value: it also removes small amounts of other substances, such as sulfur and hazardous air pollutants. The use of washed coal improves the combustion efficiency of a plant (less coal needs to be burned to produce electricity). Per unit of heat input, particulate and sulfur emissions are reduced, as are flyash disposal costs and the cost of transporting coal. Use of washed coal may also reduce plant maintenance costs and increase plant availability (Zamuda and Sharpe 2007).

I examine the costs and benefits of using washed coal at the Rihand plant, which is located in a coal-mining area and is thus not currently required to use beneficiated coal. Rihand is a 2,000 MW plant that in 2008 produced 17,000 GWh of electricity, using coal with a sulfur content of 0.39 percent and an ash content of 43 percent. I assume that using washed coal would reduce the ash content of coal burned to 35 percent and the sulfur content to 0.34 percent and would raise the heating value of coal by 17 percent. Based on

[56] It is also called coal beneficiation.

information provided by the CEA, I calculate the levelized cost of electricity generation (lcoe) at Rihand using unwashed coal to be 1.206 Rs/kWh. I estimate that using washed coal increases the lcoe by 16.5 percent, to 1.405 Rs/kWh (see Appendix). My cost analysis focuses only on the yield and direct operating costs of washing. Other researchers have found that the use of washed coal leads to significant gains in generation plant availability and plant load factor and reductions in repair costs (see, for example, Zamuda and Sharpe 2007). My estimates take no account of these economic benefits, nor of likely rail freight savings.

The health benefits of coal washing (see Table 9) come from reductions in the ash content of coal, which reduces $PM_{2.5}$ emissions, and reductions in sulfur emissions. Tons of $PM_{2.5}$ and SO_2 emitted are also reduced by the fact that less coal need be burned to generate electricity. Although coal washing is usually regarded as a measure aimed at reducing SPM emissions, my analysis indicates that benefits due to the reduction in SO_2 far outweigh those of lower $PM_{2.5}$ emissions. This is particularly significant because the coal used at Rihand has a sulfur content of 0.39 percent, which is lower than the average for Indian coal. My estimates assume that NO_x emissions are essentially proportional to the energy throughput of the boiler. The assumption of unchanged electricity generation thus implies unchanged emissions of NO_x.

The net impact of coal washing on mortality associated with air emissions from the Rihand plant is to save 251 lives. The increased cost of coal washing is Rs 3.39 billion, implying a cost per life saved of approximately Rs 13.5 million. This figure falls within the range of estimates of the value of a statistical life (VSL) for India which, conservatively estimated, ranges from Rs 1 million to Rs 15 million.[57]

5.2 Health Benefits and Costs of a Flue-Gas Desulfurization Unit

The Dahanu power plant in Maharashtra is currently one of three power plants fitted with a FGD (scrubber)[58]—although the MOEF stipulates that space be set aside in power plants with 500 MW and greater capacity to facilitate retrofitting of a FGD (see Table 4). The Dahanu plant is a 500 MW plant located in an environmentally sensitive area. Its SPM emissions are among the lowest in my database (32.5 mg/Nm^3 in 2008). In 2000, the Indian Supreme Court ordered that an FGD be installed at the plant.

Various scrubber technologies exist: in the United States wet scrubbing is the most common. The U.S. EPA's AP-42 database indicates that a wet scrubber can achieve up to 95 percent SO_2 removal; equipment suppliers claim SO_2 removal efficiencies of up to 99 percent with additives in the flue gas stream. The Dahanu FGD is a sea water scrubber: this type is particularly cheap to operate but has a maximum removal efficiency of about 80 percent.[59]

Capital costs of wet scrubbers range from \$100 to \$200 per KW while the auxiliary power required for operation ranges from 1.0 to 3.0 percent of plant output, depending on coal sulfur level and removal level (MIT 2007). Operating costs of FGD units in the United

[57] Bhattacharya et al. (2007) report a preferred VSL estimate of Rs 1.3 million (2006 Rs) based on a stated preference study of Delhi residents. Madheswaran (2007) estimates of the VSL based on a compensating wage study of workers in Calcutta and Mumbai of approximately Rs 15 million. Shanmugam (2001) reports a much higher value (Rs 56 million) using data from 1990.
[58] The other two are Trombay (Maharashtra) and Udupi (Karnataka).
[59] A useful source is an evaluation of control technologies considered for a power station in Hong Kong (see http://www.epd.gov.hk/eia/register/report/eiareport/eia_1232006/HTML/Main/Section2.htm).

States average 0.16 cents/kWh[60] and range up to 0.30 cents/kWh depending on sulfur level, removal efficiency and the costs (or potentially revenues) from disposal of sludge (MIT 2007). My analysis of generation costs shows that the retrofitted FGD at Dahanu adds about 9 percent to the lcoe.[61] The Dahanu FGD has very low operating costs, as it employs sea water as the reactant to absorb SO_2 rather than purchased chemicals—a design that obviously can be employed only for a plant at a coastal location. If the additional operations and maintenance (O&M) cost for a FGD is instead taken as the average figure for the United States, the effect is to increase the lcoe by a further 6 percent (see Appendix for details).

Assuming coal with 0.5 percent sulfur content and an SO_2 removal rate of 80 percent, the FGD at Dahanu saves 123 lives per year, at a cost of Rs 3.55 million per life saved. An important question is how applicable these results are to other power plants. The costs of scrubbing will be higher at plants employing conventional wet scrubbers—in the neighborhood of 15 percent of the levelized cost of electricity (see Appendix). Benefits will be lower at plants burning coal with sulfur content lower than 0.5 percent. The benefits of installing a scrubber with an 80 percent removal rate will, however, be substantial given the results in Tables 7–9: at the Rihand plant, approximately 990 statistical lives would be saved. I also note that estimated deaths per ton of SO_2 at the Dahanu plant are among the lowest of all plants in my database.

[60] See http://www.eia.gov/cneaf/electricity/epa/epa_sum.html (the EIA Electric Power Annual 2009).
[61] Cost data taken from the report of a regulatory hearing before the Maharashtra Electricity Regulatory Commission dated September 8, 2010.

6. Conclusions and Caveats

The goal of this paper is to provide bottom-up estimates of the health damages associated with coal-fired power plants in India and the benefits of reducing emissions of particulate matter, SO_2 and NO_x at individual plants. This analysis of the health effects of air emissions from coal-fired power plants is a preliminary one, using intake fraction equations derived from power plants in China to estimate the impact of power plant emissions on population exposures. I also rely on concentration-response transfer from the United States to estimate impacts on premature mortality. Because I estimate impacts only for persons aged 30 and older and only for cardiopulmonary mortality, my estimates are lower-bound estimates of health effects. As is the case for most estimates of the health effects of air pollution, the weakest part of the analysis is the atmospheric chemistry linking changes in emissions to changes in population-weighted exposures. I believe, however, that some conclusions are possible from my study.

Policies to control air pollution from Indian power plants have traditionally focused on reducing particulate emissions, due to the high ash content of Indian coal. The low sulfur content of Indian coal has, perhaps, been responsible for failure to directly control SO_2 emissions (Chikkatur and Sagar 2007). This paper suggests that more emphasis should be placed on direct SO_2 controls. The current approach—relying on tall stacks—mirrors the approach taken in the United States in the 1980s to achieve local air quality standards. Tall stacks cause pollution to be dispersed but do not eliminate exposure, especially in a densely populated country. Although Indian coal has lower sulfur content than coal mined in the eastern United States, more coal is used to produce a kWh hour of electricity in India due to the low heating value of Indian coal. This, combined with the magnitude of SO_2

emissions from coal-fired power plants, makes SO_2 the main pollutant of concern from a health standpoint.

Whether the use of FGDs to reduce SO_2 emissions passes the benefit-cost test depends on the cost of scrubbers and on plant location. I note that the scrubber installed at the Dahanu plant in Maharashtra does pass this test (i.e., it has a cost-per-life-saved below estimates of the value of a statistical life for India), in spite of the fact that the deaths per ton of SO_2 associated with this plant are among the lowest of the 89 plants in my database. Coal washing, which may pay for itself based on improved combustion efficiency and reduced transportation costs, also has health benefits due mainly to the lower quantity of coal burned per kWh generated as well as to small reductions in the sulfur content of coal burned. The percentage reduction in SO_2 emissions due to coal washing at the Rihand plant (see Table 9) is 25 percent. Due to the importance of sulfates versus directly emitted PM, the reduction in SO_2 emissions conveys more health benefits than the 30 percent reduction in directly emitted $PM_{2.5}$.

My estimates can also be used to calculate a lower bound to monetary damages per ton of $PM_{2.5}$, SO_2 and NO_x, given appropriate estimates of the VSL for India. These damages could be used to calculate pollution taxes, as well as to conduct benefit-cost analyses of specific pollution control strategies.

Tables and Figures

Table 1. *Distribution of Generation Capacity by Fuel and Region (MW) (2009-10)*

	Thermal					Renewable		
Region	**Coal**	**Gas**	**Diesel**	**Total**	**Nuclear**	**Hydro**	**R.E.S.**	**Total**
Northern	21275	3563	13	24851	1620	13311	2407	42189
Western	28146	8144	18	36307	1840	7448	4631	50225
Southern	17823	4393	939	23155	1100	11107	7939	43301
Eastern	16895	190	17	17103	0	3882	335	21320
N. Eastern	60	766	143	969	0	1116	204	2289
Islands	0	0	70	70	0	0	5	75
All India	84198	17056	1200	102454	4560	36863	15521	159399

Note: Captive generating capacity connected to the grid = 19,509 MW
Source: Central Electricity Authority, Ministry of Power, Government of India, New Delhi, 2010. *www.cea.nic.in/reports/monthly/executive_rep/mar10/8.pdf.* Accessed online December 29, 2011.

Table 2. *Ambient Air Quality Standards for PM, SO_2 and NO_x in India* [a]

Pollutants	Concentration in Ambient Air: Industrial, residential, rural and other areas		Ecologically sensitive areas (notified by central government)	
	Time weighted Averages			
	24 hourly[c, d] Standard ($\mu g/m^3$)[b]	Annual [c] Standard ($\mu g/m^3$)[b]	24 hourly[c,d] Standard ($\mu g/m^3$)[b]	Annual[c] Standard ($\mu g/m^3$)[b]
Sulphur Dioxide (SO_2)	80	50	80[g]	20[g]
Nitrogen Dioxide (NO_2)	80	40	80[g]	30[g]
Particulate Matter(RPM) PM_{10}	100	60	100	60
$PM_{2.5}$[h]	60	40	60	40
Ozone[h]	180[d,f]	100[e,f]	180[d,f]	100 [e,f]

a. National Ambient Air Quality Standards (NAAQS) adopted November 18, 2009.
b. $\mu g/m^3$: microgram per cubic meter.
c. Annual average: arithmetic mean of minimum 104 measurements in a year at a particular site taken twice a week 24 hourly at uniform intervals.
d. 1-hourly
e. 8-hourly
f. 24-hourly, 8-hourly, or 1-hourly monitored values, as applicable, should be complied with 98 percent of the time in a year. However, 2 percent of the time, these may be exceeded, but not on 2 consecutive days of monitoring.
g. Standards are applicable uniformly across residential and industrial areas, with the exception of these more stringent standards for NO_2 and SO_2 in the Ecologically Sensitive Areas.
h. Fine particulate matter ($PM_{2.5}$) and Ozone standards were added in 2009. Other new parameters, such as arsenic, nickel, benzene and benzo(a) pyrene have been included for the first time under NAAQS based on CPCB/IIT Research, World Health Organization guidelines and European Union limits and practices (See Department of Environment and Forests, Government of NCT of Delhi, 2010).

(Source: Central Pollution Control Board, Government of India. Accessed on April 2, 2012: http://cpcb.nic.in/National_Ambient_Air_Quality_Standards.php.)

Table 3. *Particulate Emissions Standards for Coal Based Power Plants*

Capacity	Pollutant	Emission limit
Coal based thermal plants		
Below 210 MW & plant commissioned before 1.1.82	Particulate matter (PM)	350 mg/Nm^3
210 MW & above		150 mg/Nm^3

Source: Central Pollution Control Board website, accessed on April 2, 2012
Note: The Andhra Pradesh Pollution Control Board and Delhi Pollution Control Committees have stipulated stringent standards of 115 and 50 mg/Nm^3 respectively for control of particulate matter emissions.

Table 4. *Stack Height Requirements for SO_2 Control*

Power Generation Capacity	Stack Height (meters)
Less than 200/210 MW	$H = 14 (Q)^{0.3}$ where Q is emission rate of SO 2 in kg/hr, H = Stack height in meters
200/210 MW or less than 500 MW	220
500 MW and above	275 (+ Space provision for FGD systems in future)

Source: Central Pollution Control Board, Government of India. http://www.cpcb.nic.in/ Accessed on April 2, 2012.

Table 5. *Distribution of Plant Performance Indicators 2008*

	All Plants , 2008							
				Percentile				
	# obs	**Mean**	**Std**	**5th**	**25th**	**Me**	**75t**	**95th**
Nameplate (MW)	90	815	663	125	320	635	114	2100
Age (Yrs)	87	21.3	11.9	2.0	13.0	20.	30.	42.6
Capacity (MW)	90	806	663	125	260	630	115	2100
Net Generation (GWh)	87	5134	4994	353	129	346	727	1600
Net Efficiency	47	0.28	0.04	0.21	0.25	0.2	0.3	0.34
Design Heat Rate	50	2407	171	222	230	235	243	2739
Operating Heat Rate	50	2855	434	230	256	275	314	3495
Specific Coal	74	0.80	0.15	0.62	0.69	0.7	0.8	1.05
Gross Calorific Value of	37	3625	389	298	331	354	386	4303

	State-owned				Center-owned				Private-owned			
	# obs	**Mean**	**Median**	**Std**	**#**	**Mean**	**Median**	**Std Dev**	**# obs**	**Mean**	**Median**	**Std**
Nameplate	57	711	640	495	22	1341	1025	860	11	306	260	158
Age	57	21.6	20.5	11.2	22	18.4	17.7	11.9	8	27.1	24.8	15.3
Capacity	57	697	630	493	22	1339	1025	862	11	307	260	158
Net Generation	57	3996	2891	3384	22	9104	7398	6905	8	2327	2226	1641
Net Efficiency	39	0.28	0.28	0.04	6	0.25	0.26	0.03	2	0.33	0.33	0.01
Design Heat Rate	39	2405	2350	177	6	2507	2484	141	5	2301	2314	77
Operating Heat Rate	39	2866	2770	433	6	3116	3016	410	5	2460	2454	151
Specific Coal	46	0.81	0.82	0.11	22	0.78	0.72	0.20	6	0.73	0.69	0.15
Gross Calorific Value of	32	3552	3523	338	3	4238	4303	219	2	3868	3868	614

Table 6. *Distribution of Emissions and Emissions Intensity*

All Plants , 2008								
						Percentile		
	# obs	Mean	Std Dev	5th	25th	Median	75th	95th
Min SPM recorded	75	117	118	24	65	103	132	216
Max SPM recorded	75	207	271	61	116	143	187	535
Mid-point SPM recorded	74	155	156	41	92	125	149	325
PM 2.5(tons/year)	66	2580	3263	176	619	1867	2547	7682
PM 2.5 (g/Mwh)	66	436	539	95	226	300	421	1102
SO_2 (tons/year)	74	37216	31722	3437	14501	30423	51098	104426
SO_2 (g/Mwh)	73	6860	4107	4545	5468	6111	6996	8845
NO_x (tons/year)	73	14261	11397	1833	5500	13341	19419	40085
NO_x (g/Mwh)	73	2442	540	1500	2082	2383	2788	3258

	State-owned				Center-owned				Private-owned			
	# obs	Mean	Median	Std Dev	# obs	Mean	Median	Std Dev	# obs	Mean	Median	Std Dev
Min SPM recorded	49	139	122	138	20	90	84	35	6	26	26	6
Max SPM recorded	49	254	157	324	20	127	128	51	6	88	86	32
Mid-point SPM recorded	49	186	137	182	19	106	105	42	6	57	58	16
PM 2.5(tons/year)	42	2892	1956	3844	19	2502	1909	1751	5	260	176	146
PM 2.5 (g/Mwh)	42	544	376	649	19	273	253	107	5	142	101	76
SO_2 (tons/year)	46	32824	33447	22191	22	53689	39271	43488	6	10486	7960	9381
SO_2 (g/Mwh)	46	7481	6554	4929	22	5827	5749	1784	5	5693	5388	1241
NO_x (tons/year)	46	12217	11988	8848	22	20708	14628	14181	5	4700	4046	3270
NO_x (g/Mwh)	46	2551	2518	503	22	2260	2269	540	5	2250	2250	706

Table 7. *Distribution of Deaths Attributable to Emissions—All Plants 2008*

	# obs	**Mean**	**Std Dev**	**Percentile**				
				5th	**25th**	**Median**	**75th**	**95th**
Deaths (All	66	581	465	90	249	486	764	1556
Total deaths per								
PM 2.5	66	56	76	5	14	38	63	164
SO_2	66	392	335	60	175	315	522	1124
NO_x	66	127	97	25	51	103	167	309
Deaths per ton of								
PM 2.5	88	0.022	0.005	0.014	0.019	0.022	0.026	0.028
SO_2	88	0.010	0.002	0.007	0.009	0.010	0.011	0.012
NO_x	88	0.009	0.002	0.006	0.007	0.008	0.010	0.011
Deaths (per Gwh)	66	0.095	0.033	0.054	0.075	0.090	0.105	0.140
Total deaths (per								
PM 2.5	66	0.010	0.013	0.003	0.005	0.007	0.010	0.020
SO_2	66	0.063	0.023	0.037	0.051	0.061	0.070	0.090
NO_x	66	0.021	0.006	0.013	0.017	0.021	0.024	0.032

Note: 1. Deaths per plant figures based on plants with data for all three pollutants; 2. Beta= 0.005827 and baseline deaths adjusted by COPD proportion.

Table 8. *Distribution of Deaths Attributable to Emissions by Plant Ownership Status 2008*

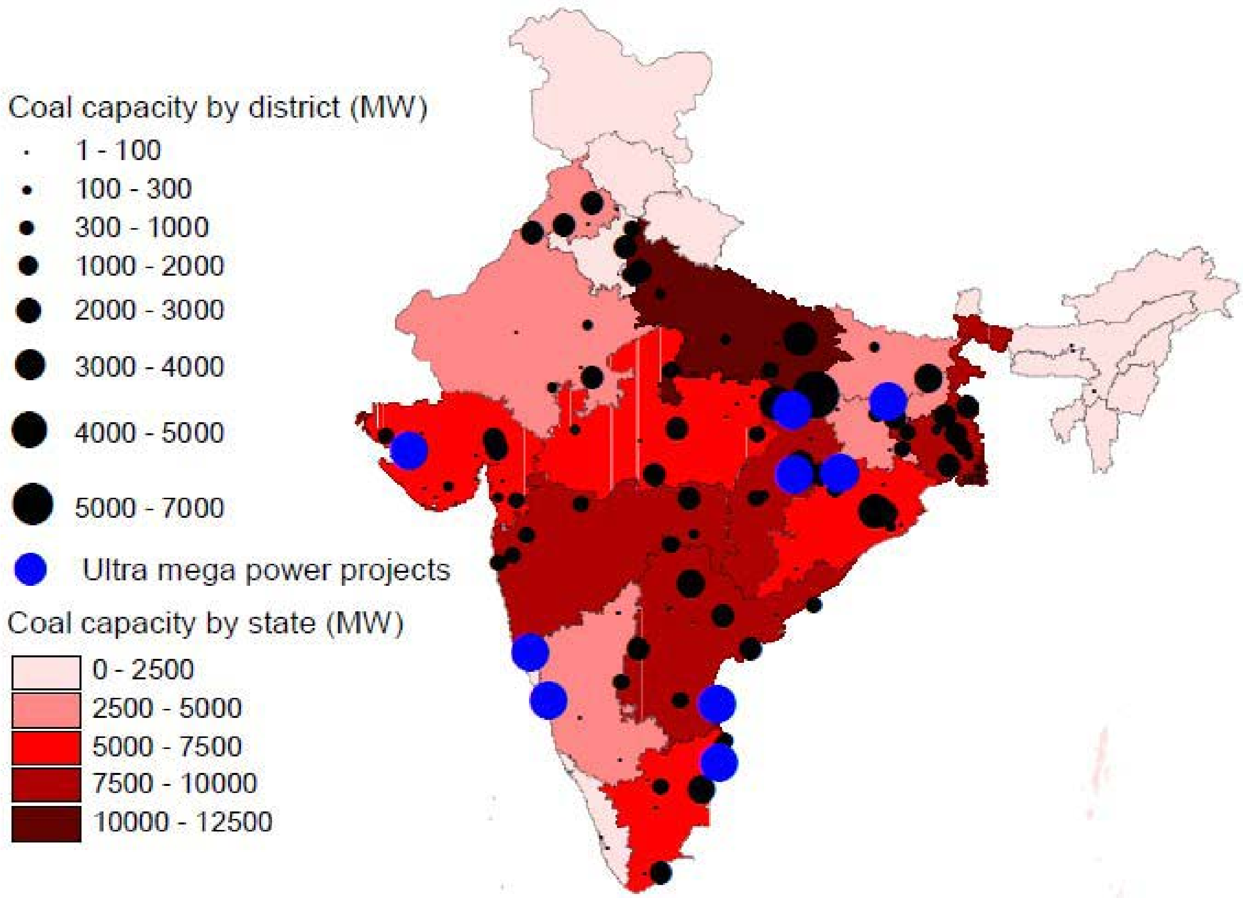
	State-owned				**Center-owned**				**Private-owned**			
	# obs	**Mean**	**Median**	**Std Dev**	**# obs**	**Mean**	**Median**	**Std Dev**	**# obs**	**Mean**	**Median**	**Std Dev**
Capacity	57	697	630	493	22	1339	1025	862	11	307	260	158
Total Deaths (All	42	525	439	358	19	818	575	608	5	154	142	89
Total deaths per plant												
PM 2.5	42	61	38	90	19	58	53	41	5	6	5	4
SO_2	42	348	300	235	19	563	380	471	5	109	95	68
NO_x	42	110	103	71	19	189	158	124	5	37	40	17
Deaths per ton of												
PM 2.5	56	0.022	0.022	0.004	22	0.022	0.024	0.006	10	0.022	0.022	0.005
SO_2	56	0.010	0.010	0.001	22	0.010	0.010	0.002	10	0.009	0.010	0.001
NO_x	56	0.009	0.008	0.002	22	0.009	0.010	0.003	10	0.008	0.009	0.002
Total Deaths (per Gwh)	42	0.101	0.094	0.037	19	0.086	0.083	0.023	5	0.076	0.073	0.025
Total deaths (per												
PM 2.5	42	0.012	0.008	0.016	19	0.006	0.006	0.003	5	0.004	0.003	0.002
SO_2	42	0.067	0.065	0.025	19	0.058	0.055	0.019	5	0.052	0.049	0.014
NO_x	42	0.022	0.021	0.006	19	0.020	0.018	0.006	5	0.020	0.021	0.008

Note: 1. Deaths per plant figures based on plants with data for all three pollutants; 2. Beta= 0.005827 and baseline deaths adjusted by COPD proportion.

Table 9. *Effects of Coal Washing at Rihand Thermal Power Station, 2008*

	Unwashed coal	Washed coal	% reduction due to washing
Coal usage (`000 tons)	10903	9322	14%
$PM_{2.5}$ (tons/year)	1732	1207	30%
SO_2 (tons/year)	77854	58032	25%
NO_x (tons/year)	25828	25828	0%
Total deaths (all pollutants)	1241	990	20%
Total deaths due to			
$PM_{2.5}$	43	30	30%
SO_2	934	696	25%
NO_x	264	264	0%
Deaths (per GWh)	0.074	0.059	20%
Total deaths (per GWh)			
$PM_{2.5}$	0.0026	0.0018	30%
SO_2	0.0548	0.0409	25%
NO_x	0.0155	0.0155	0%

Figure 1. *Distribution of Coal-Fired Power Plant Capacity*



Source: Uwe Remme, Nathalie Trudeau, Dagmar Graczyk and Peter Taylor, Technology Development Prospects for the Indian Power Sector, Information Paper, IEA, February 2011.
Note: Ultra mega power projects (UMPPs) are power projects planned by the Government of India to reduce power shortages. They are supercritical plants with a minimum capacity of 4 GW.

III. Chapter 3

Tightening Environmental Regulation in India: An analysis of the cost-effectiveness of SO_2 control technology for Indian power plants[62]

1. Introduction

The impact of SO_2 and its derivative secondary sulfates on human health is well studied. Inhalation of fine sulfates has been linked to increased mortality risk from respiratory diseases including cardiopulmonary disorders and lung cancer (Pope et al. 2002). Countries such as the United States, which burn coal with high sulfur content have enacted regulation to limit SO_2 emissions for over 2 decades. In response, power plants subject to the regulations either switched to low sulfur coal or installed a flue-gas desulfurization (FGD) unit. As a result, in 2010, power plants with installed FGD units accounted for about 60% of the electricity generated from coal in the US (EIA).

[62] This research benefitted from the support of Mike Toman at the DEC-EE group of World Bank who funded the atmospheric dispersion modeling used in the analysis. The modeling was carried out by Sarath Guttikunda at UrbanEmission.Info in New Delhi, India.

India in contrast, currently has only three FGD units in operation and no formal restrictions on SO_2 emissions from power plants.[63] As a result, despite the low sulfur content of Indian coal, health impacts from unregulated SO_2 are substantially greater than those form emissions of $PM_{2.5}$ and NO_x (see chapter 2). With expanding coal-based electricity generation and an increasing reliance on higher-sulfur imported coal there is a growing need to consider more stringent limits on SO_2 emissions from coal fired power plants—which account for almost 50% of the SO_2 emissions in the country.

In this paper, I examine the economics of FGD retrofits at power plants across India from a social planner's perspective. Specifically, I conduct a cost-benefit analysis of installing FGD units at power plants at various locations in India. I construct estimates of capital and operating costs using information obtained from power purchase agreements and regulatory hearings. I consider two varieties of FGD technology that are available in the Indian market—wet limestone FGDs and sea water FGDs. Both technologies use different SO_2 scrubbing processes and thus have different capital and operating costs. I compare the cost estimates to estimates of health benefits from a reduction in SO_2 emissions. The calculation of health benefits uses results from a Lagrangian Puff transport model that links SO_2 emissions from each power plant in my sample to population-weighted changes in ambient sulfate concentrations.[64] This is combined with a dose-response function transferred from Pope et al. (2002) to estimate the reduction in mortality associated with the change in ambient sulfate concentrations.

[63] The three FGDs are at the plants at Trombay (Maharashtra), Dahanu (Maharashtra) and Udupi (Karnataka).

[64] I consider only sulfate particles formed from SO_2 emissions, and not ambient SO_2 for the estimates of health impact. This is because secondary sulfates are responsible for the majority of the premature mortality associated with SO_2 emissions.

The results show that mandatory FGD retrofit at all power plants in the sample will incur an average annual cost of Rs. 127 crore, and an average cost per life saved of approximately Rs. 6 million ($109,000 at an exchange rate of 55 Rs./$). The results also identify plants and locations where the investment in an FGD delivers positive net benefits. They also allow me to compare FGD installation across geographical locations to determine where pollution control delivers the greatest net benefits. The net gains from FGD installation are driven by the proximity to densely populated areas, the size of the plant and the sulfur content of coal used[65]. A significant proportion of FGD retrofits result in a cost per life saved that lies within the range of reasonable VSL estimates for India. Accounting for the fact that my estimated benefits may be considered a lower bound, this implies that adoption of SO_2 control equipment in India is economically feasible and should be seriously considered as a policy option.

The rest of the paper is organized as follows. Section 2 presents a brief background of SO_2 regulation in India along with a discussion of the prevalent FGD technology options facing the Indian electricity sector. Section 3 describes the methodology used to construct estimates of costs and benefits. Section 4 discusses the results from the cost-benefit analysis and discusses policy implications. Section 5 concludes.

2. Background

2.1 SO_2 control in India

Air pollution regulations on power plants in India have historically focused on restricting particulate emissions. This is mainly because of the characteristics of Indian coal—the primary

[65] The latter two determine the quantity of emissions from the plant in a given year.

fuel for electricity production in the country. Indian coal has an ash content of 45%, compared to about 10% for Ohio and 6.6% for Powder River Basin (PRB) coal in the United States (EIA, 2009). The high ash content results in a large amount of particulate pollution in the post combustion gases. This is emitted into the atmosphere unless captured using devices such as electrostatic precipitators (ESPs)[66]. The sulfur content of coal on the other hand is comparatively low—on average about 0.3-0.5% by weight, which is comparable to the sulfur content of PRB coal.

Coal-fired electricity production has been expanding rapidly in India over the past decade. With large unmet demand from millions of people without access to electricity the rate of expansion in coal-based capacity is expected to remain high in the medium term. The growing demand for coal from new capacity, and even from increasing capacity utilization at existing plants, is being met by greater imports of higher sulfur content coal from countries like Indonesia, Australia and South Africa.[67]

The expansion in coal-based generation and coal imports has increased the pressure on policymakers to tighten pollution standards for SO_2. In addition to minimum stack height restrictions (see Chapter 2), which dilute the pollutant in ambient concentrations by dispersing it over a wider area, the Central Electricity Authority (CEA) has also required that all new plants leave space in the plant for the possible retro-fitting of FGD units. According to the CEA there are 8 power plants (both greenfield projects and expansions to existing plants) expected to be commissioned in the next 2-3 years with FGDs installed to control SO_2 pollution (see Table 1).

[66] All coal-fired power plants in India are equipped with ESPs.

[67] Imported coal also has greater heat content per kilogram compared to domestic Indian coal. Imported coal is often blended with domestic coal to reduce costs compared to using only higher priced imported coal. This also reduces the average sulfur content depending on the ratio of the blend.

The expectation of tighter emissions standards for SO_2 has created an interest in the FGD markets in India. As of this writing there are only three functioning FGDs in India. The first FGD installed was at the Trombay power plant, a privately owned coal and gas plant near Mumbai. The other plants are Dahanu (also in the state of Maharashtra) and Udupi (Karnataka). Though all three plants are privately owned, the FGD installation at these plants was ordered by the local environmental authorities or courts.

2.2 FGD Technology

A flue-gas desulfurization unit (FGD) or scrubber is an end-of pipe technology that removes SO_2 from combustion gases before they exit the smokestack. The process essentially involves treating the flue gas with an alkaline substance that reacts with the acidic SO_2 to form a by-product that can be removed as waste before flue gases are emitted.

There are many different FGD technologies available for SO_2 removal. The most prevalent one, a wet limestone FGD (wFGD), involves treating the gases with a limestone slurry, which may be sprayed on the gas in an absorber unit (see Figure 1). The byproduct produced is gypsum, which is can be sold commercially as it is used in the construction industry. Approximately 85% of the scrubbers installed in the US are wet scrubbers (EPA, 2004).

Another rapidly expanding technology is sea water FGD (swFGD). These units use the alkalinity of sea water to remove SO_2 from the flue gases. The by product is water, which is treated and discharged back into the sea. While there are other technologies that are available and in operation around the world,[68] wFGD and swFGD are the two that are currently proposed for power plants in India.

3. Methodology

3.1 Sample of Plants and Data Construction

My dataset consists of 72 coal-fired power plants (shown in figure 2) which have information available to calculate SO_2 emissions at the plant-level.[69] There are 45 plants owned by the state government, 22 owned by the Central government and 5 privately owned plants, with a total nameplate capacity of approximately 68 GW. The data, derived from the CEA, has 90 plants in 2008, with a nameplate capacity of approximately 73 GW—96 per cent of the total installed capacity at coal-fired plants in that year. The 72 plants analyzed here, thus account for approximately 90 per cent of the total coal-fired capacity in the India in 2008.

Table 3A shows that the average SO_2 emissions for these plants was 37,727 tons in 2008. There is considerable variation in the emissions of SO_2 across plants—from a minimum of 778 tons to a maximum of 188,010 tons. This is due to variation in the sulfur content of coal, plant size and generation. The average sulfur content of the sample is 0.53% (with a standard deviation of 0.19%).

For this analysis, I construct estimates of SO_2 emissions based on benchmark operating conditions for power plants—85 per cent capacity utilization. This implies that my estimates of

[68] See DTI (2009) for a description of the various technologies of FGDs available around the world.
[69] Information on the operating characteristics of power plants was obtained from annual publications of the CEA (see Chapter 1 for a detailed description of the data sources). Estimates of SO2 emissions were constructed from information from the CEA, various sources of data on coal quality and engineering estimates of the combustion parameters of boilers in India (see Chapter 2 on details of emissions estimates).

annual tons of emissions are not affected by yearly fluctuations in operations and conform to the industry benchmark set by the CERC[70].

Using the estimates based on benchmark operations, I calculate deaths associated with SO_2 emissions from each plant, as described below. In conducting cost-effectiveness analyses of scrubber installation, I analyze the results from two subsets of power plants. First, I choose the 30 plants that have the highest emissions of SO_2 in a given year (the analysis in this paper is for the year 2008). The installation of FGDs in these plants would result in the greatest reduction in total tons of SO_2 given the number of plants selected. Second, I choose the 30 plants for which SO_2 emissions are associated with the highest sulfate deaths per year. Though there is an overlap in the plants selected by both criteria, differences in surrounding population density and weather conditions cause the two samples to differ. Figures 2 and 3 show a maps of the power plants selected in both samples.

Figure 2 shows the full sample of coal-fired power plants in my data. It shows that power plants are fairly spread out over the country, though there is some clustering of power plants close to the coal mines. Figure 3, shows the 30 plants with the highest annual SO_2 emissions. These 30 plants are spread out across all but 2 states in the sample—Delhi and Assam.[71] The plant with largest annual emissions is Ramagundem STPS, a Center owned plant, which emits approximately 170 thousand tons of SO_2 per year. The total SO_2 emissions from all these plants combined is slightly above 2 million tons per year. Figure 4, displays the top 30 plants in terms of attributable sulfate deaths. These plants are mostly in densely populated areas in the northern and eastern parts on

[70] The CERC assumes a benchmark capacity utilization of 85 per cent for tariff setting.
[71] There are a total of 17 states with coal-fired power plants in India.

India. Farakka STPS, with 1082 deaths attributable to SO_2 emissions is associated with the greatest amount of damages. In total, the top 30 plants are responsible for 11,700 deaths from SO_2 emissions.

3.2 Atmospheric Dispersion Modeling

To estimate health impacts from specific pollution sources, one needs to estimate the changes in ambient air quality that are attributable to emissions from those sources. This is done using pollution dispersion models that track the transport of pollutants though the atmosphere using information on weather, topography and pollutant chemistry. Dispersion models vary based on the amount of information they require as an input to the calculations and thus the computing resources that they require.

Broadly, dispersion models may be either process-based or reduced form (NRC, 2010). The former use detailed atmospheric chemistry to simulate interactions among pollutants and gases in the atmosphere and thus accounts for non-linearity in the dispersion process. These models demand substantial computing power and are very time-intensive to run; making it feasible to conduct only a limited number of runs. They are most often used to simulate the joint impact of multiple sources of pollution rather than predicting individual impacts of a large number of sources—as is the case here.

Reduced form models use simplified dispersion calculations to predict concentration changes. These models are calibrated to fit the predictions of more complex process models while minimizing the complexity and data-requirements of the underlying calculations.

The model used in this analysis, ATMoS 4.0,[72,73] is a reduced form Lagrangian puff transport model.[74] Its relatively low data and computational requirements allow running the model for the full sample of power plants in my data. The dispersion model was run separately for each plant to trace the impact of primary SO_2 emissions (leading to a formation of sulfate particles), emissions of NO_x and directly emitted particulate matter on fine particle concentrations. The modeling domain was restricted to the political boundaries of India so as to estimate impacts within the country. The derived output is a source-receptor matrix for each source which enables the plant-by-plant study of the impact of emissions.

One concern with the use of a model like ATMoS is that it may fail to capture the non-linearity in the dispersion process, such as that due to the interaction of pollutants. This may be especially true for nitrate concentrations, formed from NO_x reacting with ammonia, as ammonia reacts preferentially with SO_2 to form sulfates. Nitrate formation would thus be affected by the combination of SO_2 emissions and the ammonia in the atmosphere. However, in this analysis I focus on sulfate formation, which is roughly linear in emissions conditional on meteorological conditions. Further, the amount of ammonia in the atmosphere over India is sufficiently high for it not to be a constraint on either sulfate or nitrate formation. For these reasons, ATMoS can be

[72] The dispersion modeling for this analysis was carried out by Sarath Guttikunda at UrbanEmission.Info in New Delhi, India based on emissions and location data provided by the author.

[73] This model is a modified version of NOAA's Branch Atmospheric Trajectory (BAT) model (Heffner 1983). Guttikunda and Calori (2009) provide some detail on the workings of the basic ATMOS 4.0 model created for urban-level studies. The model used in this analysis was modified for a national scale study.

[74] Lagrangian puff models mathematically track individual puff movement through the atmosphere as a random walk process—a Gaussian random-walk for horizontal progression in the case of ATMOS4.0. Final dispersion results are derived by calculating the statistics of the trajectories of multiple puffs.

considered to provide reasonable estimates of ambient sulfate concentration changes due to precursor SO_2 emissions.

A drawback of ATMOS4.0 is the limited geographical range of the modeled dispersion. The model is constructed to be able to track pollutant puffs when their impact on ambient concentrations exceed a threshold of a certain percentage of the initial size of the puff. This limits how far from the source pollution particles are followed. Thus, the ATMOS model is best suited to predict medium-range impacts of pollution—less than a 500 km radius around the source. The estimated impacts in this study should therefore be regarded as a lower bound.

3.3 Calculation of Health Benefits

The dispersion modeling results give the change in ambient concentration of fine particles associated with the emissions from each plant for each 0.25 degree grid cell in the modeling domain. This is combined with the population of each cell from the 2011 census to calculate the average population-weighted ambient concentration change attributable to the annual emissions of SO_2 from each plant.

In comparison to Chapter 2 of this dissertation, the measurement of the population-weighted concentration change is restricted to India.[75] Since the proportion of cardiopulmonary mortality in India and the United States is similar for persons over 30, I use the all-cause coefficient from Pope et al. (2002) in this analysis. The reported log relative risk for all-cause mortality in Pope et al. (2002) is 1.04, which implies a β of 0.003922 (=ln(1.04)/10).[76] Using the estimated β coefficient,

[75] In chapter 2, due to the use of the IF approach, the modeling domain covered India, Pakistan, Sri Lanka and Bangladesh.
[76] This is based on models estimated using pollution readings from 1979-83.

I compute the premature mortality associated with changes in sulfate concentrations for each power plant. The appendix (A4) of Chapter 2, gives the steps involved in the calculation of the health damages.

3.4 Cost Estimates of FGD Installation and Operation in India

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

FGDs have been in use in power plants in the United States since the 1970s to control SO_2 emissions. Studies based on operational data available for the US show that the installation and operating costs of FGD units vary substantially with the size of the plant (EPA 2009; Sargent and Lundy 2007). Further, costs of installation increase substantially when retrofitting the FGD unit to an old plant, as compared with the installation of an FDG in a new plant. This is due to the fact that for an existing power plant, equipment has to be moved to create space for an FGD. There are also costs associated with ductwork, wiring and modifications to the flue stack. Retrofitting an

FGD incurs a cost, on average, that is 30 percent above the cost of a newly installed FGD (Oskarsson et al.1997; EPA 2007)

The sensitivity of the costs of FGD installation and operation to local labor and material market conditions implies that the transfer of cost estimates from the US to India is inappropriate. In the case of India, there are only 3 power plants where FGDs are currently operational—with the FGDs at Dahanu and Udupi having started operations fairly recently. With the limited experience of FGD operations in the Indian power sector, data on operating and installation costs is scarce.

To construct estimates of typical FGD costs in the Indian context, I rely on information from a variety of regulatory documents. I obtain information from tariff orders issued by the State Electricity Regulatory Commissions (SERC) in various states, for power plants that currently operate an FGD or from new projects that are planning to install one in the near future. I also use information from tariff determination norms and calculations of benchmark capital costs used by the Central Electricity Regulatory Commission (CERC).[77] From this information I construct an estimate of the typical capital and operating costs of wet limestone and sea water FGDs in the Indian market.

Table 2 shows the assumptions regarding the individual cost parameters used to construct the cost estimates. I assume a capital cost of Rs. 0.464 crore[78]/MW for a sea water FGD (MERC 2009; and MERC 2011) and a cost of Rs. 0.6 crore/MW for a wFGD[79]. The greater costs for a

[77] The CERC is responsible for tariff determination for all central government owned power plants and those selling inter-state power. The guidelines established by the CERC are also used by individual state SERCs in their tariff calculations.
[78] 1 crore = 10 million. Approximately $1= Rs. 55.
[79] Personal communication with an NTPC engineer. NTPC is involved in setting up a new plant in Bongaigaon, Assam which will have a wet limestone FGD installed. The FGD is being provided by an Indian company, BHEL.

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

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

To calculate total annual cost of an FGD, first, I calculate the levelized annual cost of capital. For a wFGD, this is derived from the capital cost in Rs./kWh assuming a 20 year facility life for retrofit units and a discount rate of 14 percent[81]. Next, the operating cost per unit of

According to online sources, BHEL reports a “rule of thumb” cost estimate for a wet limestone FGD to be Rs. 0.5 crore/MW. I take the more conservative (higher cost) estimate.

[80] Whether the revenue from the sale of gypsum offsets the costs of limestone processing, gypsum treatment and transportation crucially depends on regional markets for gypsum. A more accurate estimation of net variable operating costs for a wFGD would require ascertaining these market conditions.

[81] Sathaye and Phadke (2006) report a discount rate of 14 per cent derived from power purchase agreements of proposed power projects in India.

electricity produced (after adjusting for auxiliary power consumption) is added to the annualized capital cost to obtain the total annual cost of the FGD per unit of (net) electricity.

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

where,

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

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

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

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

The annual cost per unit of electricity is converted to a total cost per year using benchmark operation specifications[82] (as used by the CERC in tariff setting) instead of actual data on capacity utilization and generation. This is because operating characteristics, such as capacity utilization, may vary from year to year. In making investment decisions planners/firms will consider normative operations rather than short-term fluctuations. The assumed values for the benchmarks are shown in Table 2. The estimated costs together with the reduction in mortality due to FGD installation is used to construct the cost per life saved for each power plant.

$$Cost\ per\ Life\ Saved = \frac{(Total\ Annual\ FGD\ Cost)}{(FGD\ Efficiency * Sulfate\ Deaths)}$$

[82] A capacity utilization factor of 85%.

4. Results

The estimated emissions in this analysis are based on benchmark capacity utilization of 85 per cent. This assumption is used by the CERC for tariff setting and cost projections and therefore its use is appropriate for the calculation of long term investment decisions. Figure 5 plots the actual emissions and those based on benchmark capacity utilization.

At benchmark operation specifications, the estimates of total SO_2 emissions and deaths for the 72 power plants in my data are roughly 3 million SO_2 tons per year associated with 16,933 premature deaths (Table 3B). This implies roughly 5.5 deaths per 1000 tons of emitted SO_2. If every power plant were required to install an FGD, the average annual cost for each of the 72 plants would be Rs. 127 crore, which gives an average cost per life saved of approximately Rs. 6 million ($109,000 at an exchange rate of 55 Rs./$).[83] This figure is within the range of reasonable estimates of the VSL for India of Rs. 2 million to Rs. 15 million (Bhattacharya et al. 2007, Madheswaran 2007).

To prioritize power plants for installing FGDs, one may choose those with the greatest SO_2 emissions or those associated with the greatest health damages.[84] Table 4 shows the summary results for the top 30 plants by SO_2 emissions. These 30 plants jointly emit 2 million tons of SO_2 per year (about 2/3rds of the total from all 72 plants in my sample). The average baseline deaths associated with SO_2 emissions from these plants is 335 (standard deviation of 238). There is also a fair amount of variation in the annualized cost of the FGD. The average cost is Rs. 250 crore

[83] This is the (lives) weighted average of cost per life saved = (total cost for all plants)/(total lives saved for all plants). The simple average is Rs. 7.2 million.

[84] The extent of difference between the two is determined by the variation in damage per ton of pollution across the power plants.

with a standard deviation of Rs. 102 crore.[85] The cost per life saved is, on average, Rs. 6.7 million.[86] The minimum is Rs. 2.7 million per life saved and maximum is Rs. 18.4 million. The estimated costs are in the range of the Value of Statistical Life estimates for India—a range of Rs. 2 million to Rs. 15 million.[87] Of the 30 plants in the sample roughly 15 plants have a cost per life saved of less than Rs. 10 million. For the FGD installation to past the cost-benefit analysis, the cost per life saved must be above the appropriate VSL. Considering an arbitrary value of Rs. 10 million for the VSL (taken from the range of Rs. 2-15 million), the installation of an FGD will pass the benefit-cost test for 15 plants, leading to a reduction of 6,120 deaths per year at a total cost of Rs. 3321 crore (thus an average cost per life saved of Rs. 5.4 million). Figure 6 displays the results for deaths, emissions and cost per life saved from FGD installation.

Table 5 shows the summary results for the 30 plants with the highest baseline sulfate deaths. SO_2 emissions from these 30 plants are responsible for 11,721 deaths per year (roughly 59 per cent of the joint total baseline deaths from all 72 plants in my data). The average sulfate deaths per year for these 30 plants is 391 (standard deviation of 204) from an average SO_2 emissions of 58,963 tons per year per plant. The average cost per life saved is estimated to be Rs. 5.1 million per plant,[88] with a minimum of Rs. 1.6 million and a maximum of Rs. 14.7 million. Thus the cost of FGD installation at the most expensive of these 30 plants is below the upper bound of the VSL for India (Rs. 15 million). Considering again the arbitrary value of Rs. 10 million, 26 of 30 plants have a cost per life saved below the VSL.

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85 However, given the way that costs are constructed in this analysis, this is largely driven by variation in the size of the plant.
86 This is the (lives) weighted average of the cost per life saved. The simple average is Rs. 8.6 million.
87 There are only a few studies of VSL in India. See chapter 2 for brief discussion of VSL figures for India.
88 Weighted average. Simple average is Rs. 5.5 million.

The results suggest substantial scope for the efficient adoption of FGDs by coal-fired power plants in India, from a social perspective. Depending on the VSL chosen, the result shows that the installation of FGD units at many power plants across India will result in net benefits.

The results also help understand the factors driving the estimated cost per life saved. The cost per life saved is calculated as the ratio of annual FGD cost and the annual lives saved from a reduction in SO_2 emissions (a proportion of total deaths due to sulfates). FGD costs are a function of the type of FGD and the size of the plant; whereas lives saved are a function of the tons of emissions and the exposed population around the plant.

$$Cost\ per\ Life\ Saved = \frac{f_1(Plant\ size, FGD\ type)}{f_2(SO_2 tons, exposed\ population)}$$

The exposed population around the plant, along with meteorological conditions, determines the marginal damages (deaths per ton) of emissions. Thus,

$$Cost\ per\ Life\ Saved = G(Plant\ size, FGD\ type, SO_2 tons, Deaths\ per\ ton)$$

To examine the marginal contribution of each of the drivers of the costs and benefits of FGD installation, Column [1] of Table 6, displays results from the estimation of the above equation. Column [2] includes coal use per unit electricity and coal sulfur content as explanatory variables instead of tons of emissions[89]. Column [3], estimates a log-log form of the equation and gives estimates of elasticities. The results show that the population around the plant, as proxied by the deaths per ton of SO_2, is a strong and statistically significant predictor of the cost per life saved from FGD installation in India. Column [3] shows that conditional on plant size, sea water FGDs

[89] Sulfur content of coal, coal used per unit electricity and the generation together determine the tons of SO2.

have 27 per cent lower annual costs than wet limestone FGDs. It also shows that the elasticity of the cost per life saved with respect to the sulfur content of coal is -0.8[90]. As expected, the coefficient on nameplate capacity is insignificant. This is because the size of the plant both increases cost and, all else equal, the emissions. Thus, the effect on the ratio is indeterminate.

Figure 8 plots plants with cost per life saved less than Rs. 5 million on a map. All except 2 plants[91] are in the heavily populated northern and eastern parts of the country, confirming the importance of population in the vicinity of the plant as an important driver of the cost per life saved. Figure 9, plots the plants with estimated cost per life saved between Rs. 5 million and 10 million. The map shows that these plants are more spread out over the rest of the country.

5. Sensitivity

It is important to test the sensitivity of the results to the key assumptions underlying the calculations. Examining the impact of changing assumptions such as average coal quality also helps understand the impact of future scenarios on policy effectiveness.

With increasing imports of coal, the average sulfur content of coal used in India is likely to increase. I examine the how my results change if the average sulfur content of coal increased by 50 per cent. As the dispersion of sulfur is approximately linear, the concentration changes also increase by 50 per cent. Table 7 shows that with a 50 per cent increase in the average sulfur content, emissions of 4.5 million SO_2 tons per year would lead to 25,400 premature deaths. Installation of

[90] Higher sulfur content implies higher baseline emissions and (all else equal) higher deaths. Thus the lives saved form a proportional reduction in SO2 emissions also increases.
[91] These are: Dahanu, a large plant near Mumbai; and Kutch Lignite: a plant burning very high sulfur lignite in the state of Gujarat.

an FGD at every power plant, implies an average cost per life saved of approximately Rs. 4 million ($73,000 at an exchange rate of 55 Rs./$).

The estimated results are also sensitive to the choice of the dose-response coefficient. For this analysis I transfer the beta for the all-cause coefficient from Pope et al. (2002). If instead the cardiopulmonary beta is used, the estimated impact on premature mortality is 3.3 deaths per 1000 tons of emitted SO_2 or a total of 10,365 premature deaths from cardiopulmonary causes for the 72 plants (approximately 60 per cent of the all-cause deaths estimated earlier). Installation of an FGD at every power plant, implies an average cost per life saved of approximately Rs. 9.8 million ($178,000 at an exchange rate of 55 Rs./$).

The projected capital costs for wet FGDs in India vary from 0.5 - 0.7 crore/MW. In the analysis above, I consider the value of 0.6 crore/MW. To examine the cost-effectiveness of FGD retrofit under the costliest scenario, I estimate the results assuming a capital cost of Rs. 0.7 crore/MW for the wet FGDs in my sample. The higher cost assumption raises the average annual cost of FGD operation per plant to Rs. 128 crore. This implies a cost per life saved of Rs. 6.84 million ($ 124,000).

6. Conclusions

As Chapter 2 of this dissertation makes clear, there is a need in India to consider imposing SO_2 emissions standards on coal-fired power plants FGDs are the most prevalent method of SO_2 abatement in use across the world. It is thus important to assess the extent to which tighter SO_2 standard may be met by FGD installation. To inform this, I conduct a cost-benefit analysis of FGD retro-fits at power plants across India.

The results of my analysis show that FGDs represent a viable option to reduce SO_2 emissions in India. The estimated benefits from reduced premature mortality outweigh the costs of installation and operation at a significant number of coal-fired power plants. The extent to which FGDs pass the benefit-cost test depends crucially on the choice of the VSL. However, given the range of cost estimates, it is clear that there is significant scope for FGD adoption to deliver net benefits.

Further, it is important to consider that the estimated benefits may be regarded as a lower bound to the actual benefits from reduced SO_2 emissions. There are three reasons for this. First, the dispersion modeling used to link emissions to ambient concentration changes captures medium-range transport only. Not accounting for long-range impacts is likely to significantly underestimate the health damages from power plant emissions. Second, the health impacts are restricted to premature mortality in the population above 30 years. Thus impacts on morbidity and child mortality are not considered. And third, SO_2 emissions may also have an adverse impact on other sectors such as agriculture and forestry, which are not considered here. This analysis may be also be further refined as more data become available on FGD operations in India and more recent VSL estimates are developed for India.

Tables

Table 1. *FGD Units in India - Planned and Operational*

Location	Company	State	Status of FGD	Capacity	Manufacturer	Type
Trombay	TATA Power	Maharashtra	Operating	Unit 5: 500MW	ABB	Sea water
Trombay	TATA Power	Maharashtra	Planned	Unit 8: 250MW		Sea water
Ratnagiri	JSW	Maharashtra	Under construction	1200 MW (4 x 300)	Alstom	Sea water
Udupi	LANCO	Karnataka	Operating	1200 MW (2 x 600)	Ducon	Wet Limetsone
Dahanu	RELIANCE	Maharashtra	Operating	500 MW	Ducon	Sea water
Bongaigaon	NTPC	Assam	Under construction	750 MW	BHEL	Wet Limetsone
Vindhyachal-stage V	NTPC	Madhya Pradesh	Planned	500 MW	BHEL	Wet Limestone
Mundra- Stage III	ADANI	Gujarat	Planned	1980 MW		Sea Water

Table 2. *Operating Characteristics for Cost Calculations – Baseline Assumptions*

	Units	Benchmark	
PLF	%	85	
Capital Discount Rate	%	14	
Plant Life (retrofit)	Years	20 years	
		FGD Type	
		Wet Limestone	*Sea Water*
Capital Costs	Rs. Crore/MW	0.600	0.464
Fixed Operating Costs	Rs./kWh	0.025	0.019
Variable Operating Costs	Rs./kWh	0	0
Auxiliary Consumption	%	1.5	1.25
FGD Efficiency	%	90	90
Retrofit Cost Factor	%	30	30

Note: (1) 1 crore = 10 million. (2) The capital cost above does not represent the retrofit cost factor as it is derived from information for costs at Dahanu (sea water FGD) and Bongaigaon (wet FGD) power plants. In both cases the costs reflect installation of an FGD in a new plant and not a retrofit.

Table 3A. *Summary Statistics – Actual Operations (2008)*

	Average	Std. Dev.	Median	Min	Max
Nameplate Capacity (*MW*)	948	674	840	63	3260
Generation (*GWh*)	6393	5446	5305	103	26601
Capacity utilization (%)	75	20	79	11	101
Sulfur content of coal *(%)*	0.53	0.19	0.5	0.21	2.00
SO_2 emissions (*tons/yr*)	37727	31857	30423	778	188010

Note: (1) Number of observations = 72 power plants. (2) Data based on actual operations for the year 2008.

Table 3B. *Summary Statistics – Benchmark Operations*

	Average	Std. Dev.	Median	Min	Max
SO_2 emissions (*tons/yr*)	42678	30557	36405	2704	169192
Sulfate Deaths	235	189	176	6	1083
Sulfate Deaths per GWh	0.04	0.03	0.03	0.01	0.13
Capital Costs (*Rs. crore*)	729	530	655	49	2543
Annualized Capital Cost (*Rs. crore*)	110	80	99	7	384
Operating Costs – Fixed (*Rs. crore*)	17	12	15	1	59
Total Annual Cost (*Rs. crore*)	127	92	114	8	443
Cost per Life Saved (*Rs. million*)	6.0*	4.83	6.12	1.56	31.74

***Is calculated as the (total cost)/(total number of lives saved). Simple average is Rs. 7.2 million. **Note:** (1) Number of observations = 72 power plants. (2) Calculations based on benchmark capacity utilization of 85%.

Table 4. *Summary Statistics - 30 Plants with Highest SO_2 Emissions (Tons/Year)*

	Average	**Std. Dev.**	**Median**	**Min**	**Max**
Nameplate Capacity (*MW*)	1509	613	1340	840	3260
Generation (*GWh*)	10392	5571	9238	1014	26601
Sulfur content of coal (*%)*	0.52	0.11	0.50	0.30	0.89
SO_2 emissions (*tons/yr*)	69564	29012	61436	41808	169192
Sulfate Deaths per GWh	0.031	0.021	0.021	0.013	0.091
Based on assumption of Benchmark Operations					
Sulfate Deaths	335	238	294	96	1083
Capital Costs (*Rs. crore*)	1165	490	1045	603	2543
Annualized Capital Cost (*Rs. crore*)	176	74	158	91	384
Operating Costs – Fixed (*Rs. crore*)	27	11	24	14	59
Total Annual Cost (*Rs. crore*)	203	85	182	105	443
Cost per Life Saved (*Rs. million*)	6.7*	3.7	9.7	2.2	14.7

*****Is calculated as the (total cost)/(total number of lives saved). Simple average is Rs. 8.6 million. **Note:** Benchmark operation assumes 85% capacity utilization. (2) All averages are simple averages, except cost per life saved.

Table 5. *Summary Statistics – 30 Plants with Highest SO_2 Deaths*

	Average	**Std. Dev.**	**Median**	**Min**	**Max**
Nameplate Capacity (*MW*)	1310	776	1260	248	3260
Generation (*GWh*)	8643	6797	7378	103	26601
Sulfur content of coal *(%)*	0.51	0.11	0.50	0.30	0.89
SO_2 emissions (*tons/yr*)	58963	37212	51568	13787	169192
Sulfate Deaths per GWh	0.051	0.027	0.047	0.014	0.127
Based on assumption of Benchmark Operations					
Sulfate Deaths	391	204	330	215	1083
Capital Costs (*Rs. crore*)	1022	605	983	193	2543
Annualized Capital Cost (*Rs. crore*)	154	91	148	29	384
Operating Costs – Fixed (*Rs. crore*)	24	14	23	4	59
Total Annual Cost (*Rs. crore*)	178	106	171	34	443
Cost per Life Saved (*Rs. million*)	5.1*	3.5	4.3	1.6	14.7

*****Is calculated as the (total cost)/(total number of lives saved). Simple average is Rs. 5.5 million. **Note:** Benchmark operation assumes 85% capacity utilization. (2) All averages are simple averages, except cost per life saved.

Table 6. *Determinants of Cost Per Life Saved from FGD Installation*

VARIABLES	(1) Cost per Life Saved	(2) Cost per Life Saved	(3) ln(Cost per Life Saved)
Sea Water FGD	-1.915**	-1.161	-0.272***
	(0.904)	(0.832)	(0.0275)
Nameplate (MW)	0.00368***	0.000571	
	(0.000524)	(0.000491)	
Deaths per ton of SO_2	-763.3***	-769.5***	
	(72.76)	(76.56)	
SO_2 emissions (tons/yr)	-7.04e-05***		
	(1.42e-05)		
Coal (kg/kWh)		-2.501*	
		(1.291)	
Coal Sulfur Content (%)		-468.7***	
		(115.0)	
ln(Nameplate)			0.0156
			(0.0172)
ln(Deaths per ton of SO_2)			-0.999***
			(0.0164)
ln(Coal (kg/kWh))			-0.631***
			(0.143)
ln(Coal Sulfur Content)			-0.798***
			(0.0603)
Observations	71	71	71
R-squared	0.776	0.779	0.975

Note: (1) Robust standard errors in parenthesis; (2) The regressions omit Korba STPS with an outlier estimate of cost per life saved of Rs 31 million (compared to an average of Rs. 6 million).

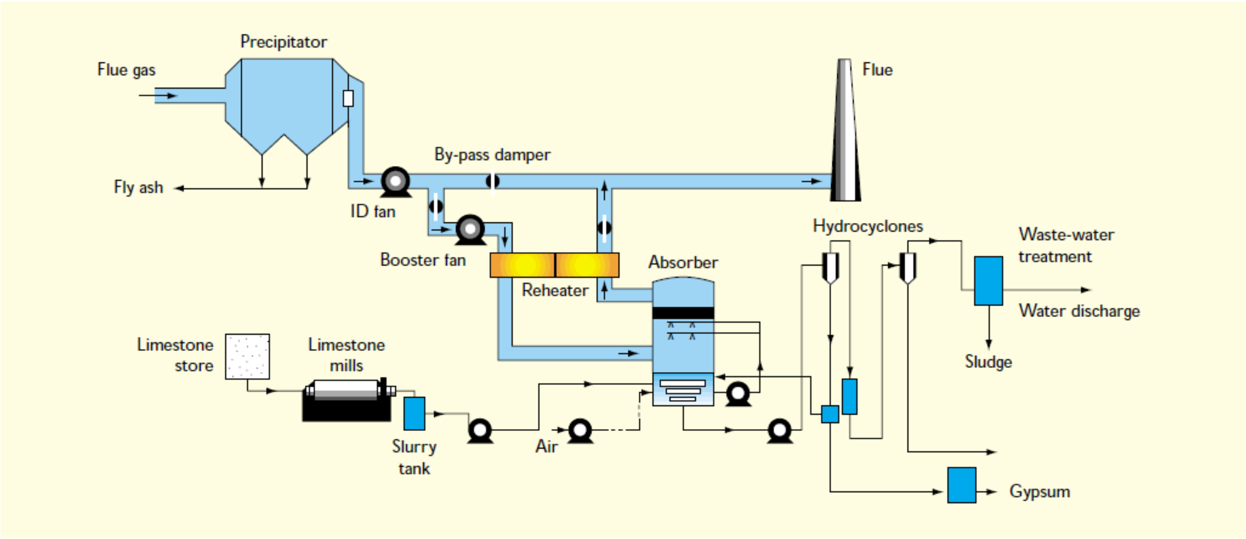
Table 7. *Sensitivity Analysis*

Assumption	Deaths per 1000 SO2 tons	Total Premature Deaths	Cost per Life Saved	FGD at plants with cost per life saved under Rs. 10 million: % Plants	SO₂ reduction	Lives Saved
			(Rs. million)		*(million tons)*	
Increase in average sulfur content of coal by 50%	5.5	25,400	4.0	99%	2.7	22,720
Capital cost of wet FGD = 0.7 crore/MW	5.5	16,933	6.84	68%	1.57	11,780
Cardiopulmonary Deaths						
Cardiopulmonary Mortality coefficient	3.3	10,365	9.8	50%	1.12	6,000

Note: The assumptions are changed one-at-a-time to examine the sensitivity of the results to each assumption.

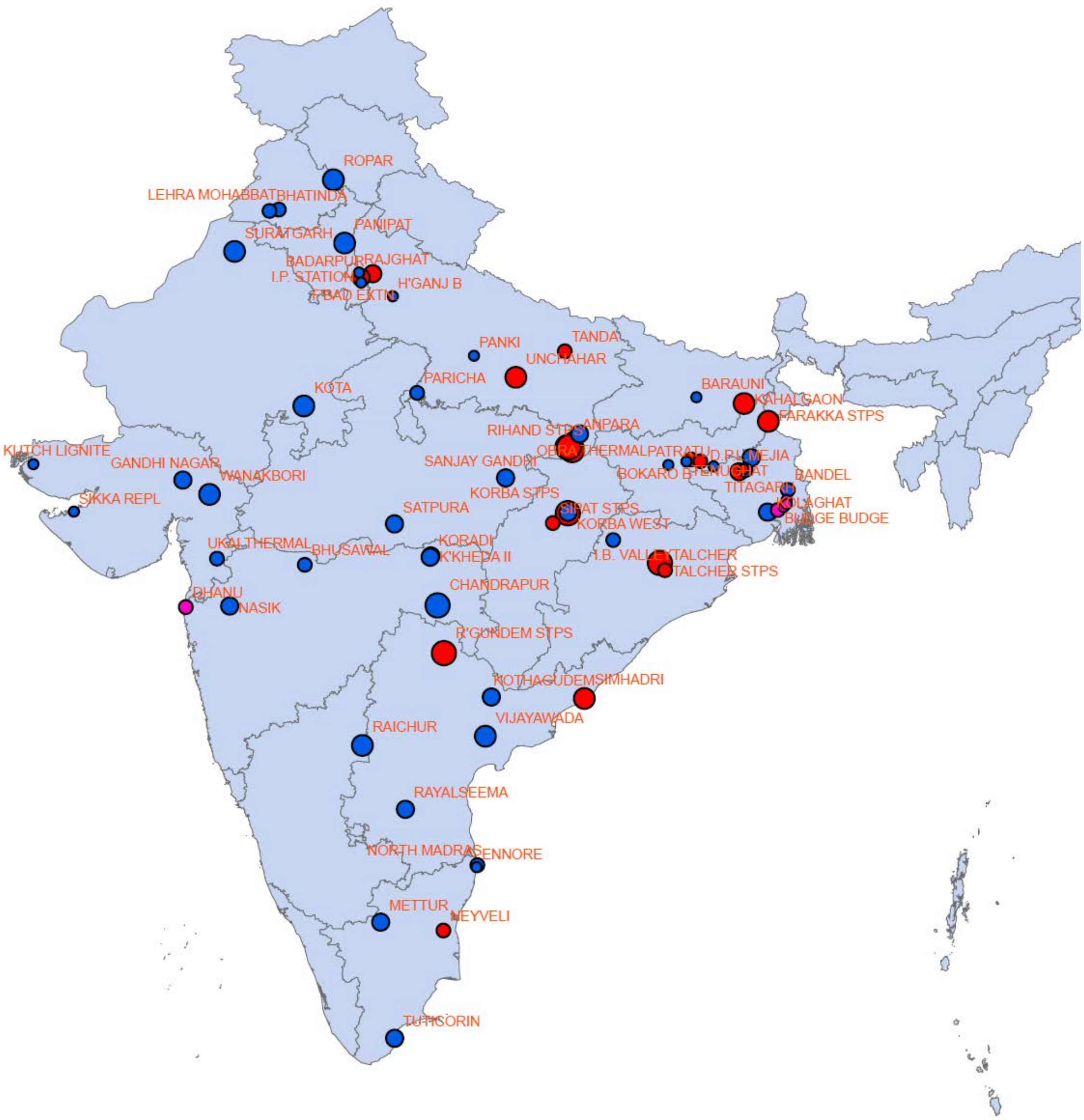
Figures

Figure 1. *Diagram of Limestone Gypsum FGD*



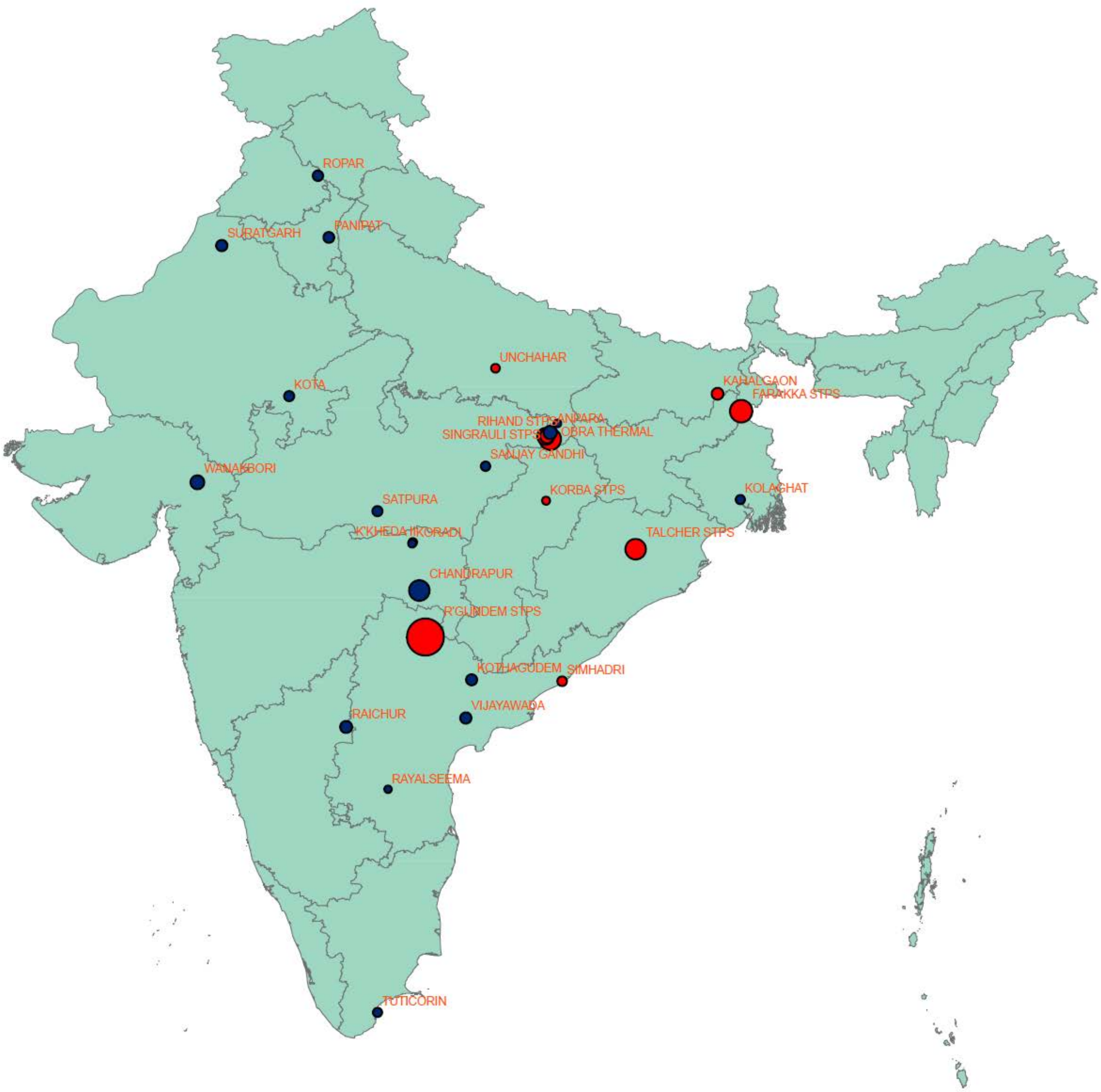
Source: DTI (2009)

Figure 2. *Coal-fired Power Plants – All Plants in Data*



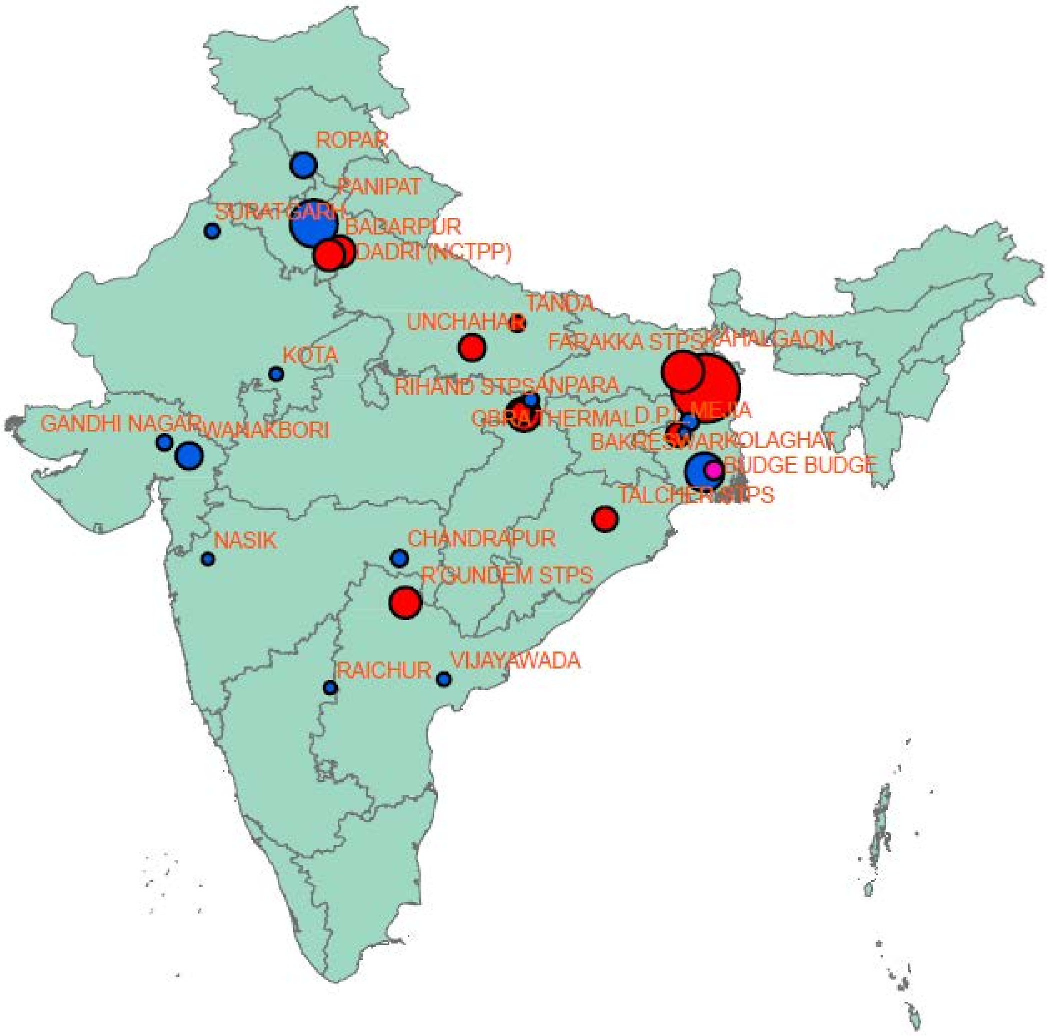
Note: (1). Red Circles--Central Government owned power plants; Blue--State Government owned power plants; and Purple—Privately owned power plants. (2) The size of the circles represents relative generation of electricity.

Figure 3. *Coal-fired Power Plants – Top 30 SO_2 Emissions (Tons/Year)*



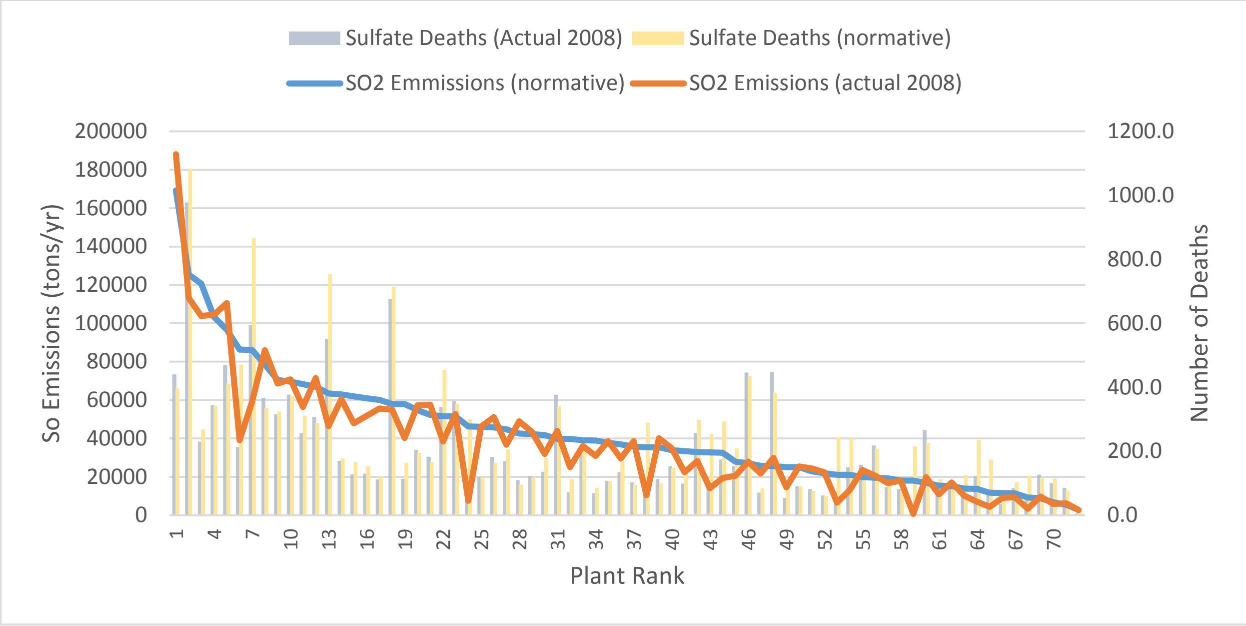
Note: (1). Red Circles--Central Government owned power plants; Blue--State Government owned power plants; and Purple—Privately owned power plants. (2) The size of the circles represents relative SO_2 emissions in tons/yr.

Figure 4. *Coal-fired Power Plants – Top 30 Sulfate Deaths*



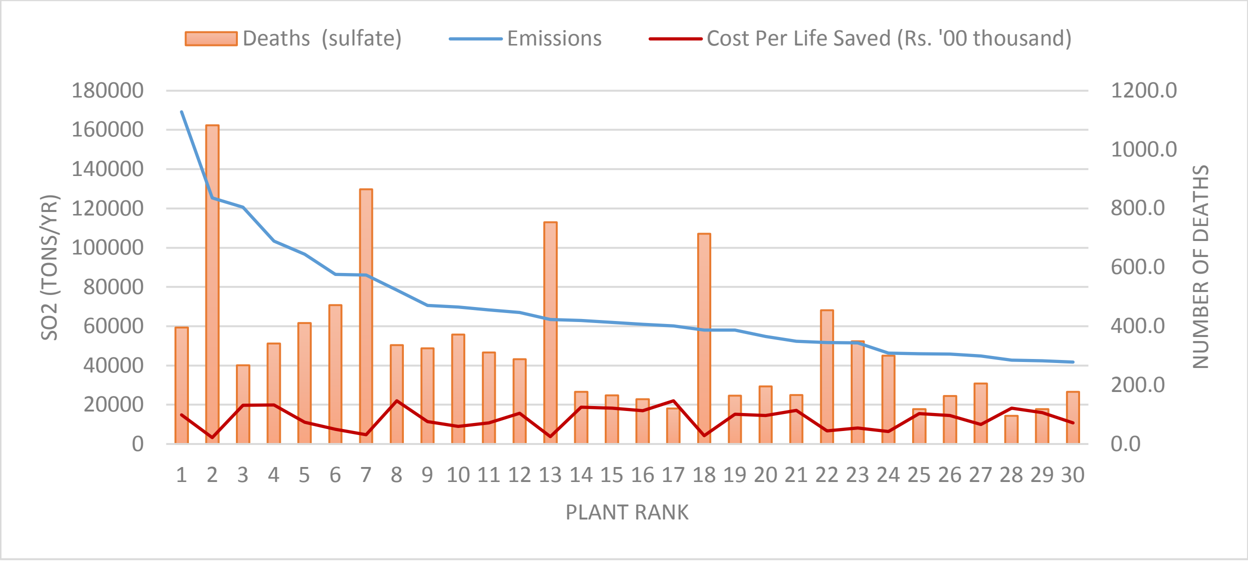
Note: (1). Red Circles--Central Government owned power plants; Blue--State Government owned power plants; and Purple—Privately owned power plants. (2) The size of the circles represents relative number of deaths per year associated with SO_2 emissions from the power plant.

Figure 5. *Emissions and Deaths - Actual vs. Benchmark Operations*

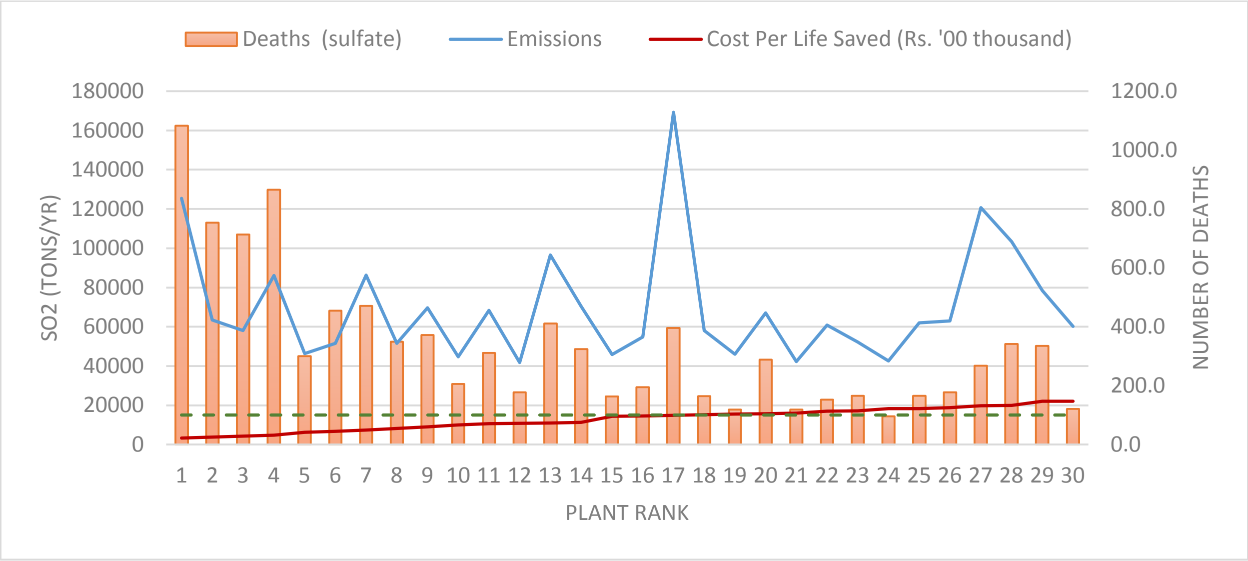


Note: (1) Sorted by actual SO2 (tons/yr) emissions. (2) Benchmark operation assumes a capacity utilization of 85%. (3) The axis plots each plant, ranked by SO_2 emissions.

Figure 6. *Emissions, Deaths and Costs of Lives Saved – 30 Plants with Highest SO_2 Emissions*

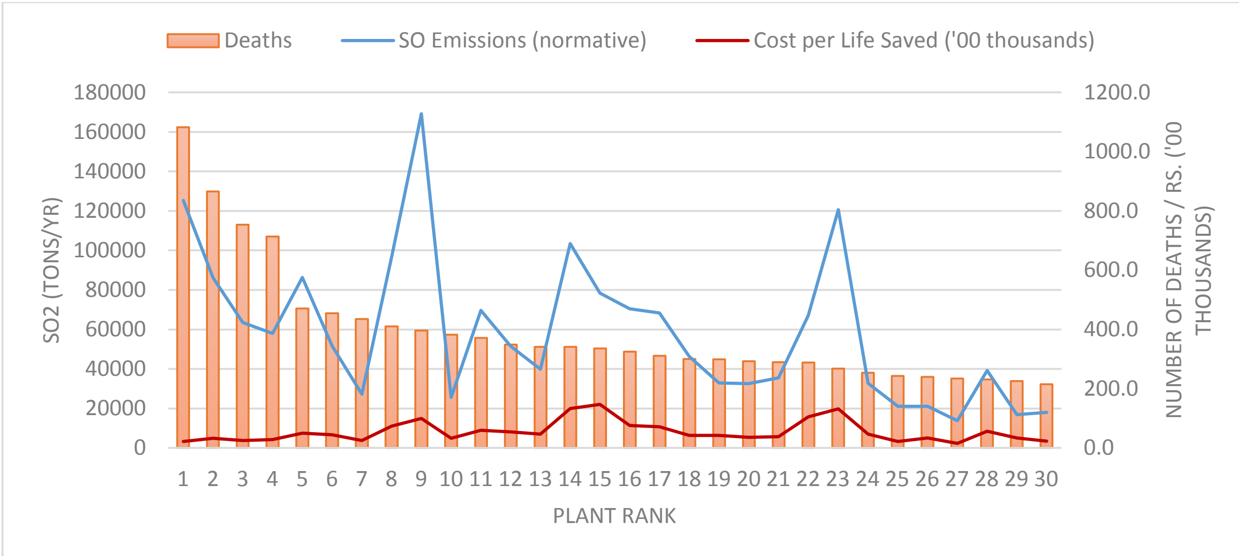


6a. *Sorted by cost per life saved*

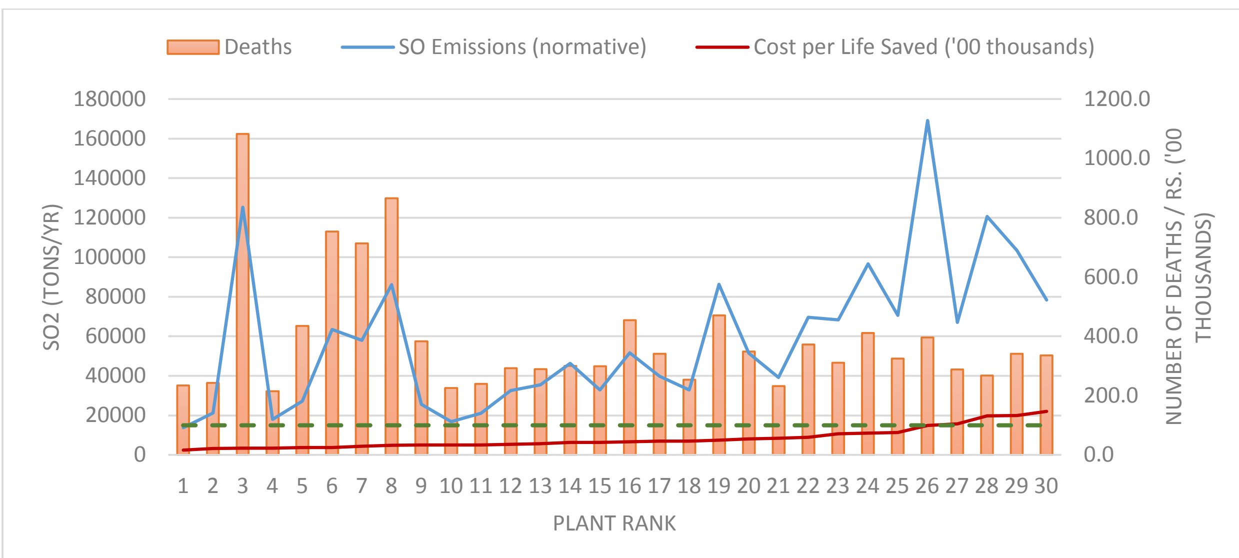


Note: (1) Figure 6 is sorted by SO_2 (tons/yr) emissions based on benchmark operations; (2) Figure 6a is sorted by cost per life saved for FGD installation; (3) Benchmark operation assumes a capacity utilization of 85%. (4) The X-axis plots each plant, ranked by the mentioned variable; (5) The dashed green line is at Rs. 10 million, which is within the range of available estimates of VSL in India (Rs. 2 million – 15 million).

Figure 7. *Emissions, Deaths and Costs of Lives Saved – 30 Plants with Highest Sulfate Deaths*



7a. *Sorted by cost per life saved*



Note: (1) Figure 7 is sorted by calculated (normative) sulfate deaths per year; (2) Figure 7a is sorted by cost per life saved for FGD installation; (3) Normative assumptions are capacity utilization of 85%. (4) The X-axis plots each plant, ranked by the mentioned variable; (5) The dashed green line is at Rs. 10 million, which is within the range of available estimates of VSL in India (Rs. 2 million – 15 million).

Figure 8. *Plants with Cost Per Life Saved less than Rs. 5 million*

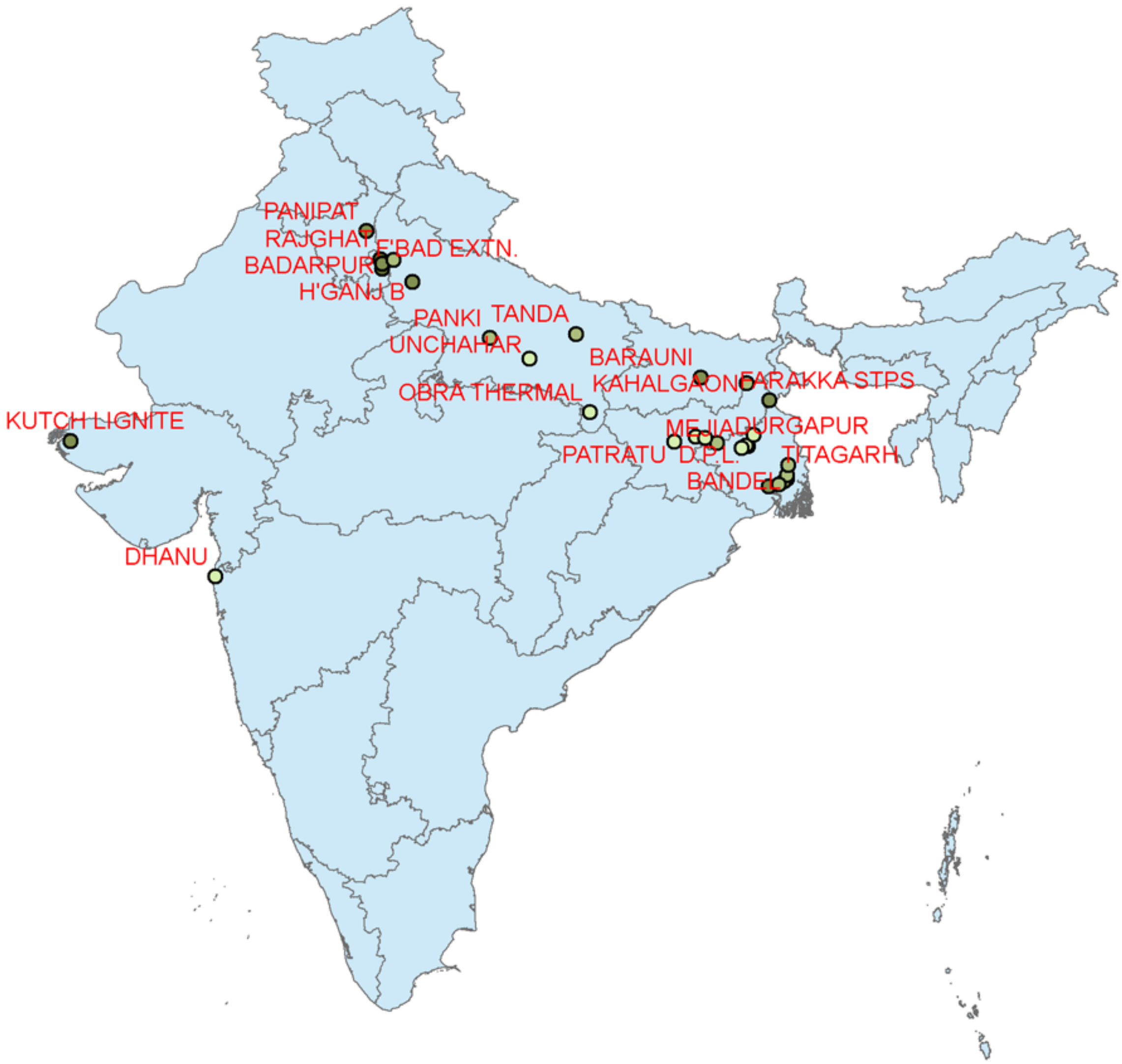
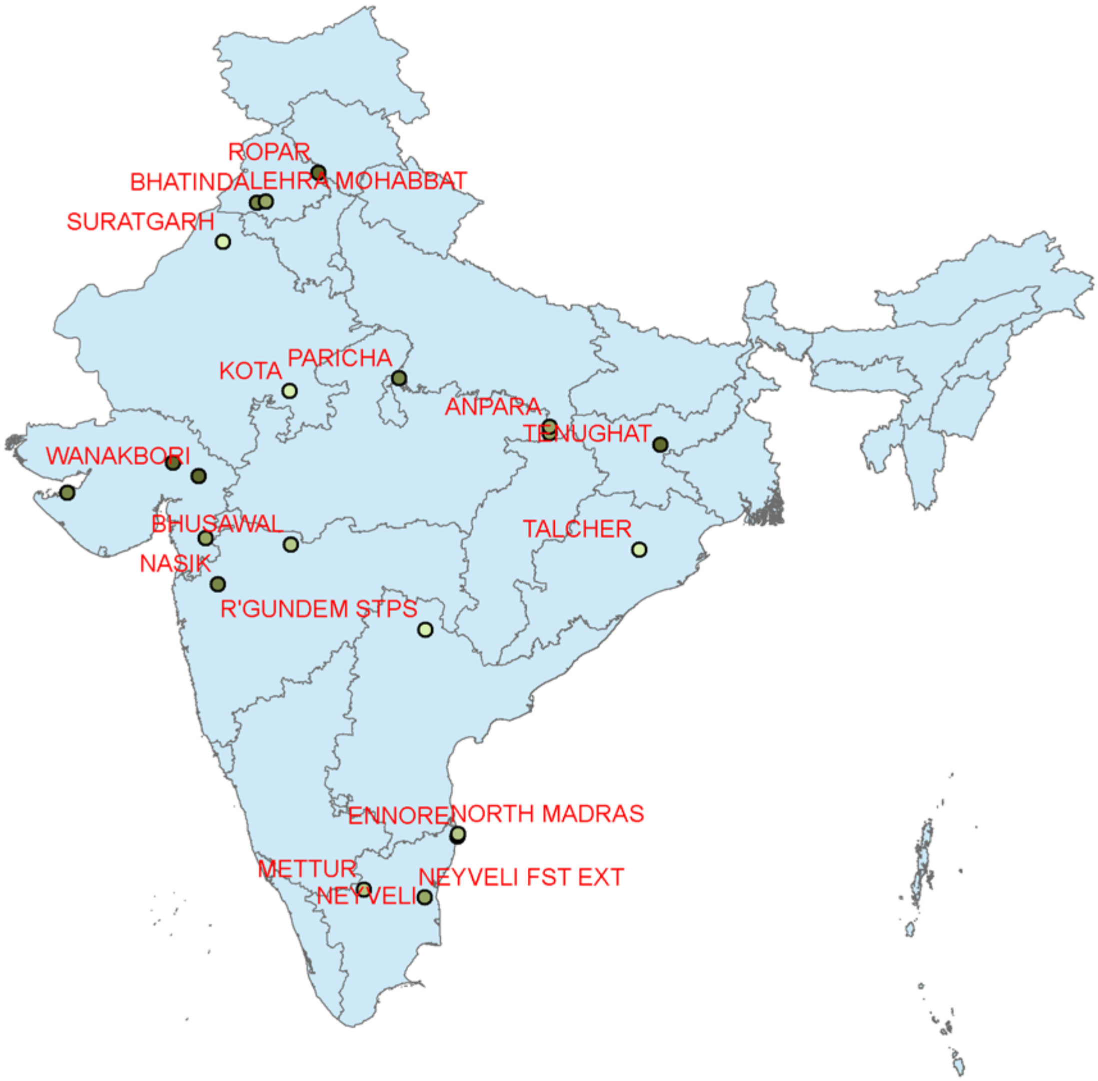


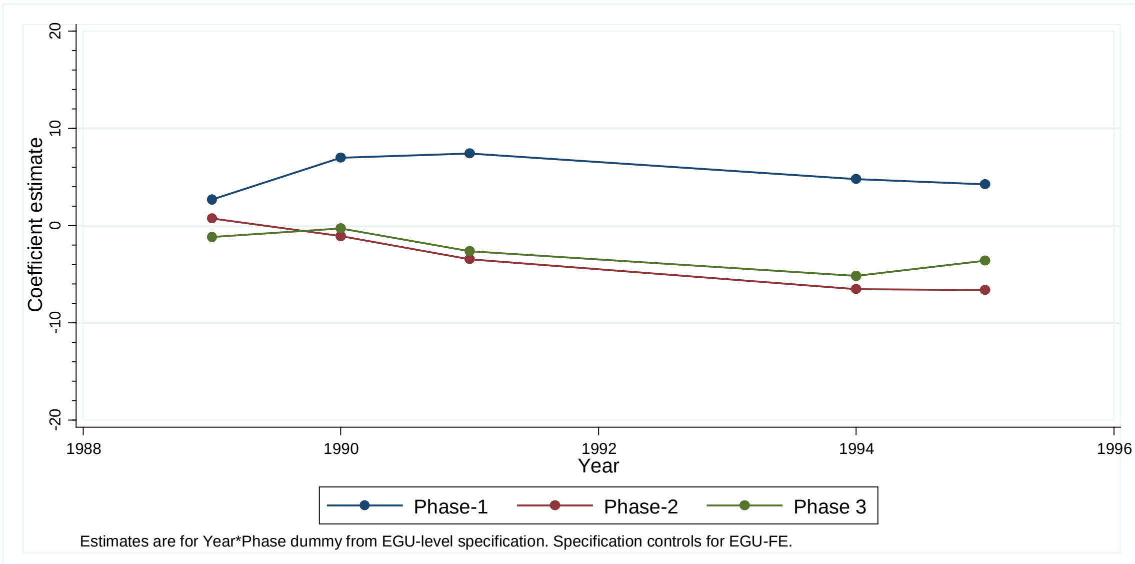
Figure 9. *Plants with Cost Per Life Saved between Rs. 5 and 10 million*



Appendices

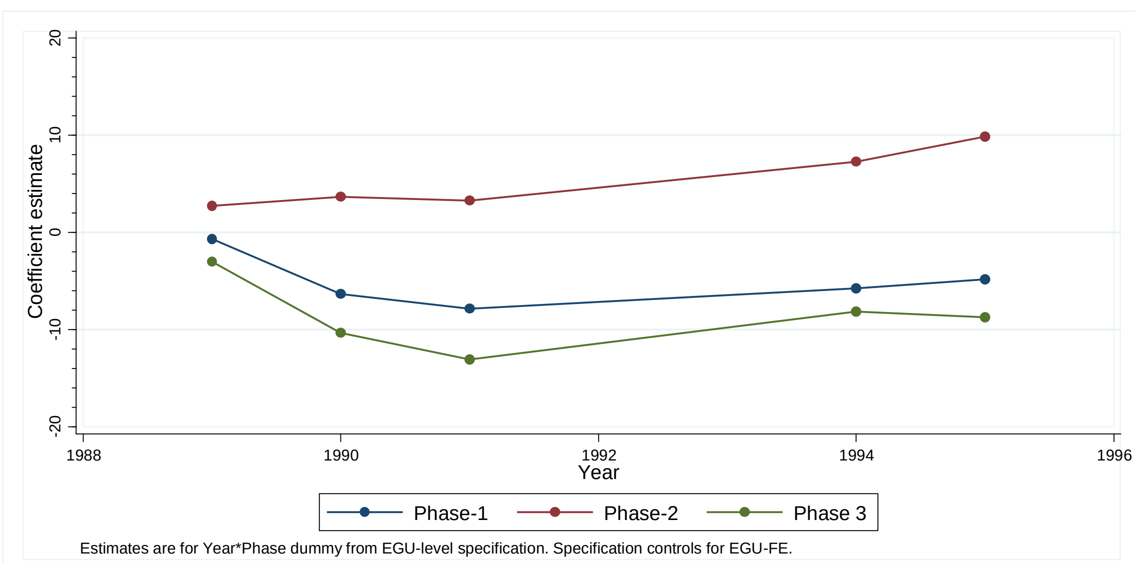
Appendix A

Table A1: *Comparison of Pre-trend – Forced Outage*



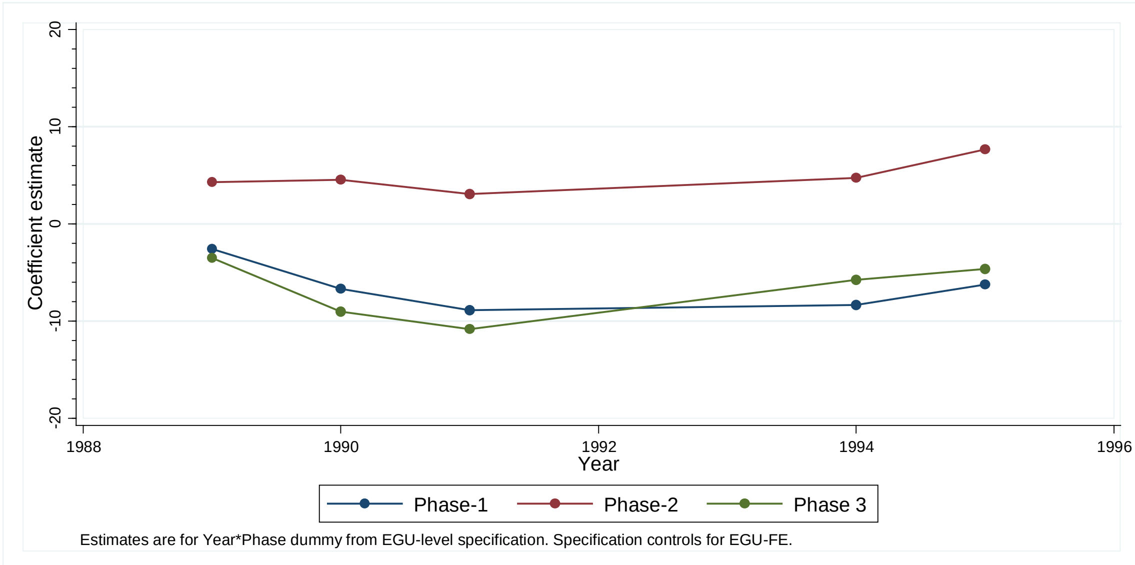
Notes: (1) Estimates of Year*Phase dummy for the period 1988-1995; (2) Specifications control for EGU fixed effects.

Table A2: *Comparison of Pre-trend – Availability*



***Notes*:** (1) Estimates of Year*Phase dummy for the period 1988-1995; (2) Specifications control for EGU fixed effects.

Table A3: *Comparison of Pre-trend – Capacity Utilization*



Notes: (1) Estimates of Year*Phase dummy for the period 1988-1995; (2) Specifications control for EGU fixed effects.

Table A4: *Falsification - Impact of Unbundling on Central EGUs*

	[1] Availability	[2] Forced	[3] Availability	[4] Forced
[Unbundled]	-1.516	-1.504		
	(2.276)	(2.407)		
[Phase-I*Unbundled]			-1.845	-2.175
			(3.306)	(3.193)
[Phase-II*Unbundled]			-0.681	0.196
			(2.104)	(2.515)
Time Trend	State	State	State	State
Unit FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes

***Notes*:** Std. errors in parentheses, clustered at state level. *** $p<0.01$, ** $p<0.05$, * $p<0.1$. All equations control for a quadratic for EGU age, year and EGU fixed effects and state time trends. Number of observations=1756 (119 Units).

Table A5: *Plant-level Clustering – Main Results*

	[1]	[2]	[3]	[4]
	DD		**DDD**	
	Availability	Forced Outage	Availability	Forced Outage
[Phase-I*Unbundled]	6.793**	-5.110**	5.959*	-4.938*
	(2.699)	(2.228)	(3.165)	(2.634)
[Phase-II*Unbundled]	-5.559**	1.599	-3.684	3.104
	(2.476)	(1.713)	(2.758)	(3.097)
Observations	4,298	4,298	6,054	6,054
R-squared	0.060	0.042	0.134	0.140
# of Units	270	270	385	385

Notes: Std. errors in parentheses, clustered at the plant level. *** $p<0.01$, ** $p<0.05$, * $p<0.1$. DD equations control for a quadratic for EGU age, year and EGU fixed effects and state time trends. DDD equations control for a quadratic for age and a full set of state*year, ownership*year, and EGU fixed effects.

Table A6: *Plant-level clustering – Robustness Results*

	[1]	[2]	[3]	[4]
	Restricted Sample - DD		**Restricted Sample - DDD**	
	Availability	Forced Outage	Availability	Forced Outage
[Phase-I*Unbundled]	6.141*	-5.134**	7.398*	-5.088
	(3.263)	(2.234)	(4.241)	(3.235)
[Phase-II*Unbundled]	-8.501***	1.434	-4.239	1.679
	(3.131)	(2.090)	(4.147)	(4.200)
Observations	2,895	2,895	4,024	4,024
R-squared	0.077	0.053	0.166	0.182
# of Units	147	147	203	203

Notes: Std. errors in parentheses, clustered at the plant level. *** $p<0.01$, ** $p<0.05$, * $p<0.1$. DD equations control for a quadratic for EGU age, year and EGU fixed effects and state time trends. DDD equations control for a quadratic for age and a full set of state*year, ownership*year, and EGU fixed effects.

Table A7: *Wild Bootstrap-t Clustering*

	[1]	[2]	[3]	[4]
	DD		**DDD**	
VARIABLES	Availability	Forced Outage	Availability	Forced Outage
[Phase-I*Unbundled]	6.793**	-5.110**	5.959*	-4.938**
	(0.04204)	(0.01201)	(0.0742)	(0.04404)
[Phase-II*Unbundled]	-5.559	1.599	-3.684	3.104
	(0.13614)	(0.53253)	(0.118)	(0.58258)
Observations	4,298	4,298	6,054	6,054
# of Units	270	270	385	385

Notes: (1) P-values in parentheses. *** p<0.01, ** p<0.05, * p<0.1. (2) Clustering at the state level uses the Wild Clustering Bootstrap-t procedure outlined in Cameron et al. 2008. (3) Results based on 1000 replications. (4) DD equations control for a quadratic for EGU age, year and EGU fixed effects and state time trends. (5) DDD equations control for a quadratic for age and a full set of state*year, ownership*year, and EGU fixed effects.

Appendix B

B.1 Calculation of Emissions Estimates – Base Case

The CEA Annual Report provides SPM emissions data for most Indian power plants in mg/Nm^3, shown as a range (the highest and lowest actual readings during the year). For each plant, the midpoint of the range was converted into grams per second using the F-factors method given in the U.S. Code of Federal Regulations (see 40 CFR Part 60, Appendix A Method 19). The F-factors calculation is based on the ultimate analysis of the coal used. A short questionnaire based survey was conducted for NTPC plants in locations across India. Information on coal quality was obtained from 9 power plants—Rihand, Farakka, Badarpur, Singrauli, Talcher, Vindhyachal, Ramagundam, Korba and Dadri. As these plants use coal inputs from different coal mines in India, the average coal characteristics from these power plants is considered representative of the rest of the country. The F-factor calculation requires a value for the oxygen content of flue gas—this was taken as 4 percent (personal communication from CEA). The resulting emissions rate for SPM was converted to $PM_{2.5}$ using data on particle size distribution from the U.S. EPA's AP-42 methodology.

Emissions of SO_2 were estimated assuming that 7.5 percent of sulfur in the coal is retained in ash with all the rest emitted as SO_2 (i.e., emissions of other oxides of sulfur taken as zero). The 7.5 percent retention figure is the mean of several values found in the literature.

Emissions of NO_x were estimated by assuming a 200 ppm NO_x concentration in flue gases (measured as NO_2) for plants fitted with low-NO_x burners and 300 ppm for all other plants. All units commissioned after 1996 are fitted with low NO_x burners.

B.2 Emissions and Economics – Coal Washing and FGD Cases

The effects on emissions and generation costs of (a) using washed coal; and (b) retrofitting flue-gas desulfurization equipment were calculated. In both cases the effect on the levelized cost of electricity (lcoe) was estimated using a model of a representative new 500 MW subcritical generation unit in India.[92] Key assumptions are described below:

a. Prior studies of the use of washed coal in India focus on economic impact—typical economic assumptions were provided by the CEA (private communication). An ultimate analysis of Dadri washed coal made for a USAID project[93] was modified to be compatible with the yield/ash reduction data provided by the CEA. Washing Dadri coal reduces its ash content by 8 percent increases the lcoe by 17 percent (c.f. advice received from the CEA that washing increases generation cost by 15–20 percent).

   This analysis (and the CEA's) focuses only on the yield and direct operating costs of washing. Other researchers have found that the use of washed coal leads to

[92] Described in "What can an analysis of CDM projects tell us about the problem of cutting greenhouse gas emissions in India?" (http://www.webmeets.com/aere/2011/prog/viewpaper.asp?pid=421) by Partridge and Gamkhar; presented at the conference of the Association of Environmental and Resource Economists, June 2011.

[93] See http://www.indiapower.org/igcc/standon.pdf.

significant gains in generation plant availability and plant load factor (PLF) and also to reductions in repair costs (see, for example, Zamuda and Sharpe 2007). My estimates take no account of these economic benefits, nor of likely rail freight savings.

The impact of washing on $PM_{2.5}$ emissions was estimated for an 8 percent reduction in coal ash content assuming that 80 percent of coal ash goes to fly ash, of which 99.84 percent is removed by the ESP. These percentages are in line with CEA advice and, averaged over a sample of modern plants, are in line with actual emissions as reported by the CEA. The impacts on SO_2 and NO_x emissions were estimated as described above.

b. The Dahanu power plant in Maharashtra is currently one of three power plants fitted with an FGD. Information on its capital and operating costs and additional auxiliary power requirement is given in a regulatory case before the Maharashtra Electricity Regulatory Commission dated September 8, 2010. Based on these data, retrofitted FGD adds about 9% to the lcoe. The Dahanu FGD has very low operating costs as it employs sea water as the reactant to absorb SO_2 rather than purchased chemicals—a design that obviously can be employed only for a plant at a coastal location. If the additional operations and maintenance (O&M) cost for a FGD is instead taken as the average figure for the United States,[94] the effect is to increase the lcoe by a further 6 percent.

Table B1. *Levelized Cost of Electricity in Various Plant Configurations (2010 Rs/kWh)*

500 MW plant with no FGD	1.134
500 MW plant with FGD: O&M cost from Dahanu regulatory hearing	1.233
500 MW plant with FGD: O&M cost from EIA data for U.S.	1.296
500 MW plant with no FGD: coal washed to 30% ash content	1.327

Note: Cost of electricity is calculated for a plant at a pithead location (i.e. no rail freight). The assumed coal price is the average Coal India Limited price for thermal coal in 2010, including royalty and similar charges but excluding value added tax.

B.3 Estimation of Health Damages using Intake Fractions

Zhou et al. (2006) used CALPUFF, a Gaussian dispersion model recommended by the U.S. EPA for long-range pollution transport studies[95] to estimate the ambient concentrations of pollutants (primary particulates with equivalent diameters of 1, 3, 7 and 13 µm; SO_2; secondary sulfates; and secondary nitrates) across a wide area due to emissions from a point source. Separate CALPUFF runs were made for hypothetical identical generation plants at 29 locations in China. By combining the resulting matrices of concentration data with a gridded population data set, Zhou et al. estimated the population-weighted average human exposure to each pollutant within a domain measuring 3,360 by 3,360 km (almost the whole of China) due to emissions from each source. The

[94] See http://www.eia.gov/cneaf/electricity/epa/epa_sum.html (the EIA Electric Power Annual 2009).

[95] See http://www.src.com/calpuff/FR_2003Apr15.pdf.

exposure estimates were converted into intake fractions (defined as "the fraction of material or its precursor released from a source that is eventually inhaled or ingested by a population" (Zhou et al. 2006)) for each pollutant at each of the 29 locations. Zhou et al. then estimated regression models for each pollutant, with intake fraction as the dependent variable (see Table A2). The independent variables used in the final models were the annual rainfall at the plant and population living within concentric annuli centered on the plant (at 100 km, 500 km and 1,000 km from the plant, and beyond 1,000 km but within the overall domain). R^2s for these models ranged between 0.89 and 0.96.

Zhou et al. did not use plant characteristics as independent variables as they assumed an identical plant at each location. However, they made a number of sensitivity analyses using alternative values for such variables as stack height. These alternative values made little difference to the results of the analysis, at least within the range (e.g., of stack heights) likely to be encountered at modern power stations.[96] Sensitivities using different assumed emission rates for pollutants showed that estimated intake fractions remained reasonably constant (Zhou et al. 2006; Zhou et al. 2003).

I used the Zhou et al. regression models to estimate intake fractions for primary $PM_{2.5}$ and secondary sulfates and nitrates for actual plant locations in India. Population estimates (i.e., populations living within 100 km, 500 km and 1,000 km of each plant location) were made using the Landscan gridded population data set for 2008 maintained by the Oak Ridge National Laboratory (ORNL).[97] The overall domain (used to estimate

[96] This is not quite true—runs using different stack heights found significant differences for large primary particles, but the impact of large particles on human health is limited.
[97] See http://www.ornl.gov/sci/landscan/.

population beyond 1,000 km) was taken as the whole of India, Pakistan, Bangladesh, and Sri Lanka. Estimates of annual rainfall are primarily from Indian data sources, but as these relate mainly to major cities and large towns, in several cases values had to be interpolated between locations reasonably close to a plant.

The methodology and assumptions used for analysis of health impacts based on these estimated intake fractions are described in the text of the paper.

Table B2. *Matrix of Coefficients for Zhou et al. Regression Models*

		Distance of Exposed Population (Radius)				
Pollutant	**R^2**	**0-100 km**	**100-500 km**	**500-1000 km**	**>1,000 km**	**Precipitation**
SO_2	0.96	9.9E-08**	1.3E-08**	3.0E-09	1.8E-09**	-6.3E-10
PM_1	0.96	1.5E-07*	2.3E-08**	1.1E-08**	3.9E-09**	-1.7E-09**
PM_3	0.92	1.4E-07*	1.7E-08**	6.4E-09	3.0E-09**	-2.4E-09**
PM_7	0.91	9.9E-08**	8.9E-09*	3.1E-09	1.5E-09*	-1.2E-09**
PM_{13}	0.89	6.7E-08**	4.3E-09	9.4E-10	7.3E-10	-4.6E-10*
SO_4	0.95	2.4E-08	7.9E-09*	6.9E-09**	2.6E-09**	-1.2E-09**
NO_3	0.93	4.3E-08	1.3E-08**	3.5E-09	2.5E-09**	-1.9E-09**

Source: (Zhou et al., 2006)

Notes: ** Estimate significant at 0.05 level.
* Estimate significant at 0.10 level.
Population variables in millions; precipitation in mm/yr.

B.4 Dose-Response Transfer for the Calculation of Health Impacts

Deaths attributable to power plant emissions are calculated as follows:

(1) Attributable deaths = (Attributable fraction of deaths) * (Baseline number of deaths)
(2) Attributable fraction = (RR-1)/RR
(3) RR = $\exp(\beta^*\Delta C) \approx \beta^*\Delta C$

where ΔC = population-weighted average change in pollution concentration (in µg/m3) and β is the slope of the concentration-response function and RR is the relative risk.

Dose-response transfer from Pope et al. (2002) gives a log relative risk value for cardiopulmonary mortality of 1.06 and β = .005827 (=ln(1.06)/10).[98] The calculated β along with the concentration change (ΔC)[99] is then used to determine the Attributable fraction (AF). In this example:

$$RR = e^{(.005827*\Delta C)} \; and \; AF = \frac{1 - e^{(.005827*\Delta C)}}{e^{(.005827*\Delta C)}}$$

The attributable fraction (AF) is the fraction of the baseline cardiopulmonary mortality that is attributable to emissions from power plants.

The baseline deaths in Pope et al. are for ages 30 and over. Calculation of baseline deaths for this analysis uses the fact that total deaths above 30 in the study region (India, Pakistan, Bangladesh and Sril Lanka) were 7.181 million. Of this, approximately 41.7 per cent of the deaths were from cardiopulmonary diseases (Indiastat).[100]

Baseline Deaths (from cardiopulmonary causes) = 7.181 million * 0.417 = 2.99 million deaths

Attributable deaths = AF * 2.99 million

[98] Using the cardiopulmonary coefficient for the 1979-83 period, when air pollution in the US was higher than in the 1999-2000 period.
[99] In the analysis, the ΔC for each plant allows the calculations to be done on a plant-by-plant basis.
[100] The proportion for India is applied to the region (which includes Pakistan, Bangladesh and Sri Lanka) since data is not available for the other countries.

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