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Contracts and constraints: How long-term power purchase agreements undermine carbon pricing in India's electricity sector☆,☆☆

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ABSTRACT

Market-based instruments like carbon pricing are increasingly being adopted in developing countries to mitigate carbon emissions. However, institutional features such as long-term electricity contracts and regulated tariffs may mute their effectiveness. I explore this question in the context of the electric power sector in India, where electricity is transacted primarily via long-term bilateral contracts and state-owned distribution utilities self-schedule contracted power plants to meet their demand. The absence of a centralized and dynamic market-based economic dispatch mechanism generates short-run misallocation in electricity dispatch and distorts long-run investment decisions, such as the incentive to invest in flexible generation capacity and energy storage to complement renewable-based capacity. Using panel data on coal price schedules and monthly plant-level operations from 2012 to 2020, I construct a predicted delivered coal price index to estimate the elasticity of plant utilization with respect to fuel prices. I find that the demand for electricity from coal-fired power plants with a higher share of capacity allocated under long-term bilateral contract(s) is less sensitive to changes in coal prices, implying that the existing market design could erode some of the environmental benefits of carbon pricing.

Economists have long argued that pricing carbon through emission taxes or tradeable permits will lower emissions to the socially efficient level (Nordhaus, 1993; Pigou, 1932). However, market-based environmental policies can yield suboptimal outcomes in the presence of distortions such as imperfect competition and incomplete regulation (Fowlie et al., 2016). Emissions leakage may occur if unregulated production can be easily substituted for regulated production (Fowlie, 2009; Fell and Maniloff, 2018). Heterogeneity in how firms are regulated has been shown to affect pollution permit market outcomes. Fowlie (2010) finds that deregulated firms in restructured electricity markets in the U.S. were less likely to adopt more capital intensive environmental compliance options as compared to rate-of-return regulated or publicly owned plants. To the extent economic regulation plays a role in determining how plants choose to respond to market-based policies, compliance costs may not be minimized as the plants with relatively low abatement costs may not be the ones investing in abatement. Furthermore, given that pollutants do not all mix uniformly, environmental damages will depend on the spatial distribution of regulated and deregulated plants. Finally, firms that can exert market power may choose to reduce markups when downstream demand reduces, implying that the pass-through of a carbon price may be incomplete (Preonas, 2024; Ganapati et al., 2020; Muehlegger and Sweeney, 2022; Fabra and Reguant, 2014; Weyl and Fabinger, 2013). In this paper, I consider the distortion introduced by features of the design of the electric power sector in India, and I study how firms operating in this industry might respond to market-based policies aimed at reducing CO_2 emissions.

Electricity is a perfectly homogenous good that can be generated from a dispatchable (e.g. coal) or an intermittent (e.g. solar) source, and therefore lends itself to being bought and sold in a single, dynamic wholesale market. Efforts to restructure electricity markets in accordance with this principle have evidently improved the operating performance of power plants, leading to reductions in carbon emissions (Davis and Wolfram, 2012; Fabrizio et al., 2007; Cicala, 2022).

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However, in many parts of the developing world, electricity continues to be transacted through systems of long-term bilateral contracts between power plants and distribution utilities, many of which experience high technical and non-technical transmission and distribution network losses and generally have a poor record of providing a reliable supply of electricity (Strbac and Wolak, 2017). In India, this market structure emerged as a result of the unbundling of generation, transmission and distribution companies from vertically-integrated state-owned utilities. Unbundling policies were enacted in various states following the passage of the Electricity Act, 2003, which aimed to introduce competition in power generation and distribution (Thakur et al., 2005).

Recent research has highlighted how differences in market institutions across countries can significantly alter the effectiveness of environmental pricing instruments. Cao et al. (2021) show that in China's electricity sector, output-based carbon pricing fails to improve overall environmental performance due to the prevalence of rigid cost-plus pricing and other command-and-control features that distort marginal incentives. Their findings emphasize that the theoretical efficiency of carbon markets can be undermined by institutional and regulatory frictions, especially in power sectors where generators face soft budget constraints or lack exposure to input cost variation. This insight is particularly relevant to India, where a majority of power is transacted through long-term contracts that decouple fuel costs from dispatch decisions. The present study builds on this literature by empirically examining how the design of electricity markets mediates the responsiveness of coal-based generators to fuel price changes, offering evidence from India's partially liberalized electricity sector.

Until the early 2000s, power generation assets in India were exclusively owned and operated by the central and state governments. Following the reforms brought forth by the Electricity Act, 2003, several private firms entered the power generation industry. India's total installed capacity stood at 350 GW in early 2019, of which nearly 46% was owned by the private sector, 25% by the central government and 30% by state governments. Of the nearly 200 GW of coal-based capacity, the shares were 39%, 29%, and 32%, respectively. As illustrated in Fig. 1, since 2012, installed thermal generation capacity has exceeded peak demand in the country, implying that there no longer remains any physical shortage of baseload generation capacity. Furthermore, while installed renewable capacity has been growing steadily since 2007, installed thermal capacity more than doubled during this period and is expected to increase in the present decade. Historically, all central government- and state government-owned plants were allocated long-term contracts covering their total installed capacity with prices determined under a cost-plus regime.[1] As part of its efforts to introduce competitive bidding for long-term contracts following the enactment of the National Electricity Policy of 2005 and the National Tariff Policy of 2006, the Ministry of Power issued "Standard Bidding Documents", which provided a template for project developers to submits bids for long-term bilateral contracts or Power Purchase Agreements (PPAs).[2] However, central government-owned power producing companies, such as the National Thermal Power Corporation (NTPC), were exempt from participating in auctions for long-term PPAs until 2011, as a result of which nearly all publicly-owned power plants that exist today were awarded long-term contracts without undergoing a bidding process.

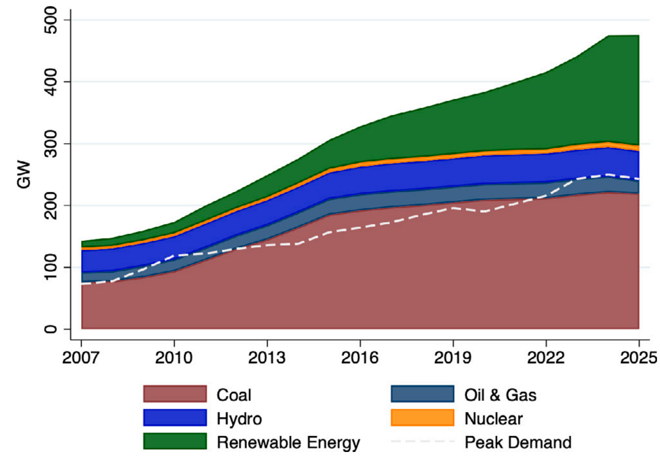


Fig. 1. Annual Installed Generation Capacity and Peak Demand, FY2007–FY2025. (The figure plots annual installed generation capacity in India by source and annual peak/maximum demand from FY 2007 to FY 2025.).

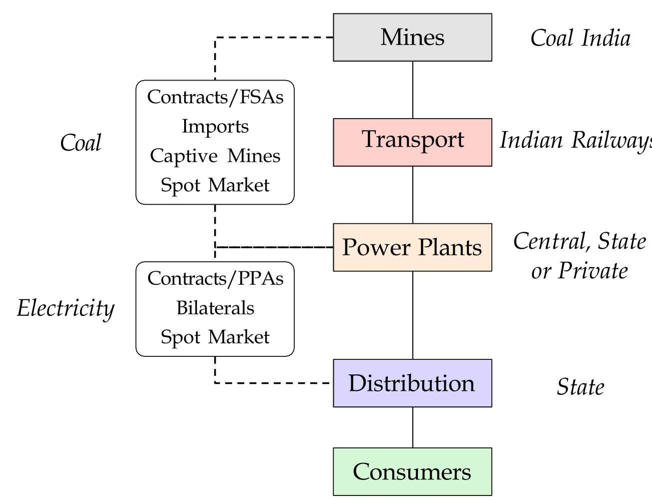


Fig. 2. Supply chain of coal-based electricity in India. (The figure presents an illustration of the mechanisms through which domestic coal is sold to power plants and electricity is sold to state-owned distribution utilities and downstream consumers.)

In order to be able to address how a carbon price would operate under the current design of the Indian power sector, I estimate how a coal plant's long-term contract status affects how its output responds to changes in coal prices. I first estimate the elasticity of coal plant utilization with respect to delivered prices of domestic coal by exploiting changes in regulated prices of coal and rail-based transportation of coal as well as taxes and surcharges on coal and transportation. Specifically, I use the time-varying tax-inclusive schedules of grade-specific notified domestic coal prices and distance range-specific notified prices for rail-based shipments of coal to construct a predicted price that holds fixed the grade composition of coal received by the plant and the distance that coal is transported before arriving at the plant during a single year in my sample. Therefore, the predicted price reflects statutory changes in the regulated prices alone and not a behavioral response to these changes. I show that the average grade in the base year is uncorrelated with plant characteristics. On average, coal prices do not have a statistically significant effect on the utilization rates of coal plants. However, heterogeneity analysis reveals that the demand for electricity from coal plants that have a higher share of their installed capacity allocated under long-term contract(s) is less sensitive to changes in coal prices.

[1] Under cost-plus or cost-of-service regulation, the regulator assesses the power plant's cost structure on the basis of a set of operating norms and parameters and adds a predetermined rate of return to determine the price at which the power plant can sell electricity.

[2] The Ministry of Power introduced two types of bidding processes for long-term PPAs. Under Case-1 bidding, the developer decides the location, technology and fuel type for the project, and is responsible for obtaining the necessary clearances. Under Case-2 bidding, the location and fuel type are decided by the distribution licensee beforehand, while the bidder chooses the technology. The distribution licensee is responsible for land acquisition, water allocation, fuel arrangements and clearances. In the case of Ultra Mega Power Projects (UMPPs), power producers are required to procure plant equipment domestically.

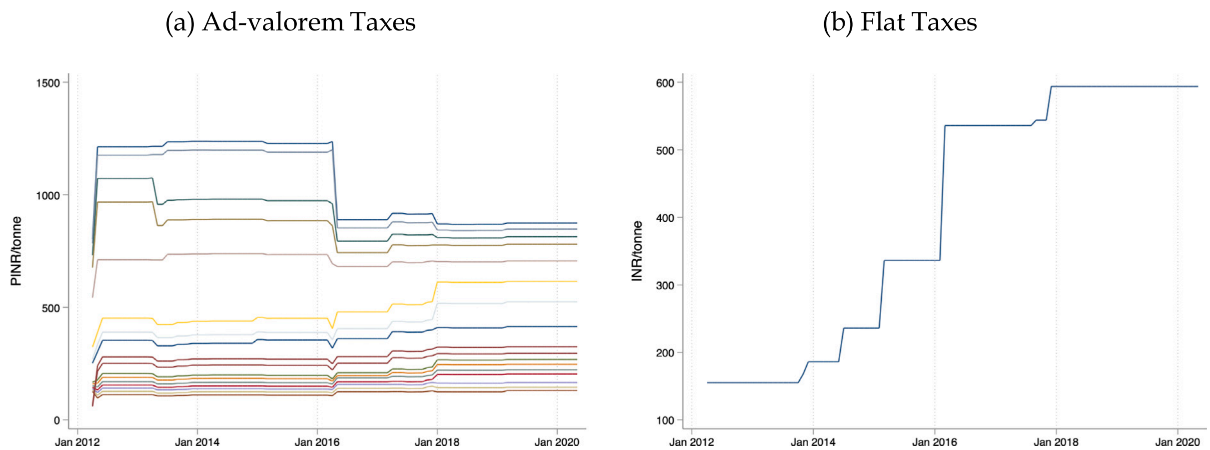


Fig. 3. Coal Tax Schedules, 2012–2020. (Figure (a) presents the time series of grade-specific ad-valorem taxes on coal and Figure (b) presents the time series of flat taxes on coal for each month from 2012 to 2020. Each colored line in Figure (a) represents a unique grade of coal. Prices are aggregated across all Coal India subsidiaries and SCCL, weighting by their annual production. The figure excludes state-specific taxes levied on coal mining.)

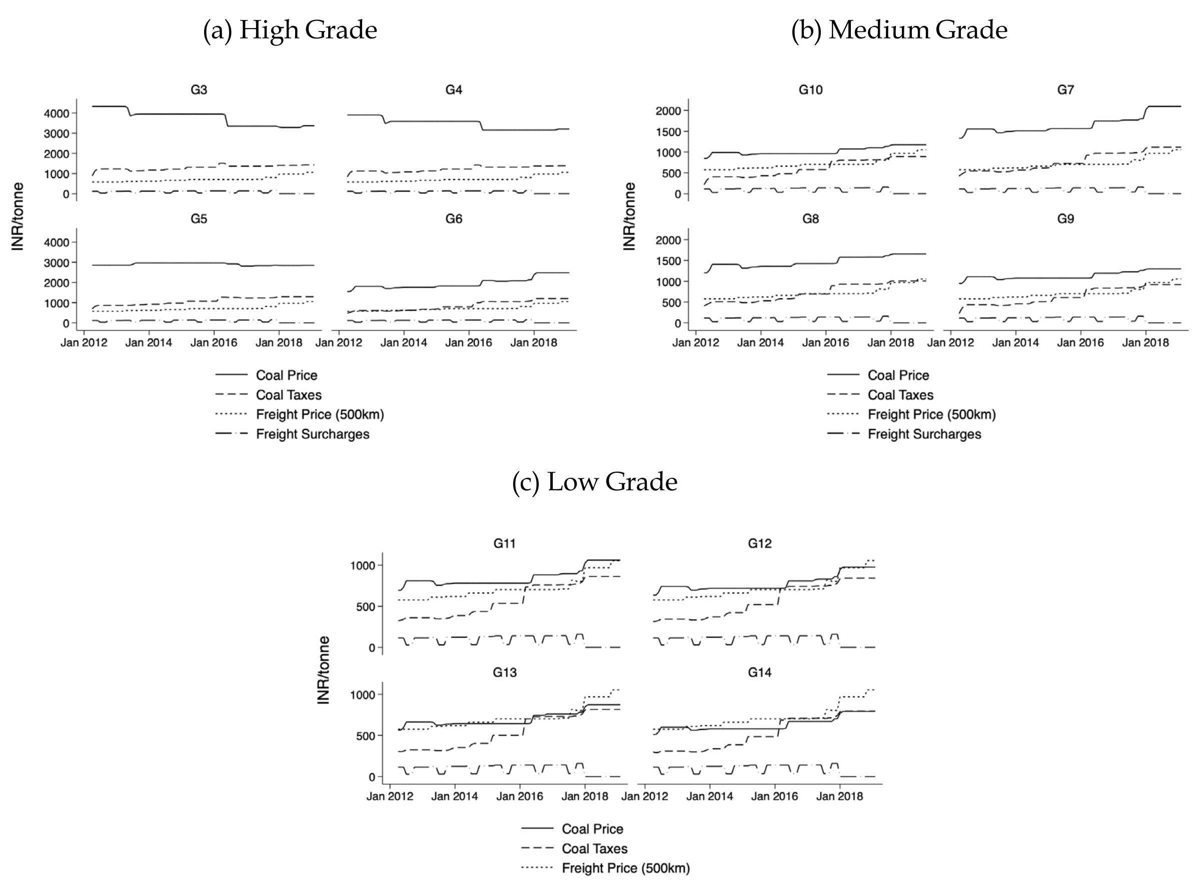


Fig. 4. Schedules of Coal Prices, Taxes, Freight Prices and Surcharges by Grade. (The figure presents the regulated coal price and taxes for each grade of coal as well as the regulated freight price and surcharges for a distance of 500 km, which is the average distance coal is transported in India, for each month from 2012 to 2020. Prices are aggregated across all Coal India subsidiaries and SCCL, weighting by their annual production. The figure excludes state-specific taxes levied on coal mining.)

The effects are largest for plants that are entirely uncontracted, for whom the estimated elasticity of utilization rates with respect to coal prices is −3.1 using monthly data and −2.9 using data aggregated at the annual level. The marginal effect of contract status on the utilization response to coal prices is robust to specifications that include controls for interactions between coal prices and age, ownership, plant size and boiler type, all of which are correlated with a plant's contract status. In future work, I will build a framework that uses the estimated elasticities to compare how a market-based policy such as a CO_2 emissions tax might operate relative to a technology or performance

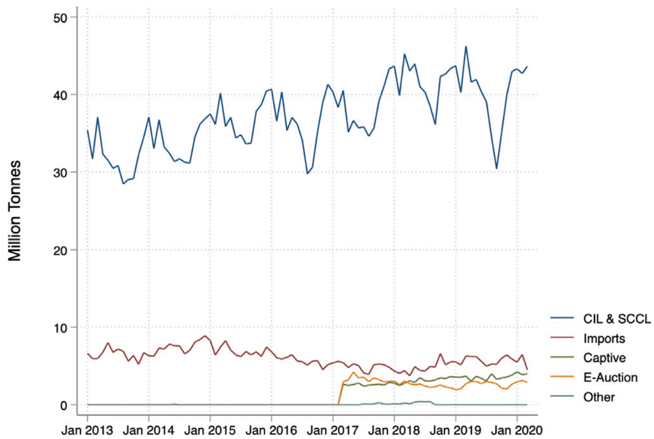


Fig. 5. Power Sector Receipts of Coal, 2013–2020. (The figure plots the time series of monthly power sector receipts of coal from public sector mining companies Coal India (CIL) and SCCL, imports, private captive mines and the CIL spot market for each month from 2012 until 2020. Data on receipts of coal from captive mines is unavailable prior to 2017.)

standard under the existing market design. This paper also bears some similarity to Harrison et al. (2016), which uses establishment-level data from the Annual Survey of Industries (ASI), a large national survey of manufacturing units in India, to compare the effects of coal prices with those of command and control (CAC) environmental regulations that the Supreme Court of India required 17 cities to enact. The authors find that higher coal prices in India are associated with lower emissions at the district level, while CAC regulations did not affect within-establishment pollution control investment or coal use, but did increase the share of large establishments investing in pollution control and reduced the entry of new establishments. It is worth noting that the ASI does not include registered electricity generation utilities, and so their analysis excludes the power sector entirely, which accounts for two-thirds of coal consumption in India and is responsible for nearly half of the country's annual CO_2 emissions (International Energy Agency, 2020).

This paper is organized as follows. Section 1 provides an overview of the existing design of the electricity sector in India with an emphasis on the structure of long-term bilateral contracts and the pricing of domestic coal. Section 2 describes the data and provides a discussion of descriptive statistics and trends. Section 3 explains the empirical strategy and robustness analysis. Section 4 covers the estimation results and Section 5 reviews the implications of the findings for policy. Section 6 concludes with some directions for future work.

1. Institutional setting

1.1. Electricity market design

A schematic of the supply chain of coal-based electricity in India is illustrated in Fig. 2. More than 90% of electricity in the country is transacted through long-term bilateral contracts between state-owned distribution companies and power plants, rather than via competitive wholesale markets. Traditional 25-year Power Purchase Agreements (PPAs) for electricity consist of a monthly two-part tariff paid to the plant owner by an electric distribution utility, the vast majority of which are state-owned. The fixed or capacity charge is calculated on the basis of annual fixed costs, which are composed of the return on equity, the interest on loans and working capital, depreciation and operations and maintenance (O&M) expenses. Power plant owners with a long-term PPA are entitled to recover their entire fixed charge if they declare their capacity available to their contracted state's system operator, known as the State Load Dispatch Centre, for at least 85% of the time in a month.[3][4] The variable or energy charge is composed of the delivered cost of fuel, inclusive of all taxes, and regulated transmission charges. Changes in notified prices or taxes are considered "Force Majeure" or a "Change in Law" and are automatically passed-through into the variable charge. Neither of these charges have any time-of-day component and typically do not change within the month. As a result, long-term contract prices do not factor in the dynamics of renewable energy availability and therefore weaken the market incentive to develop flexible power generation or energy storage to complement renewable capacity.

Using long-term bilateral contracts to transact electricity generates two broad sources of inefficiency. First, newer, more efficient plants may be underutilized if they enter the market without long-term contracts. The rules governing the power sector have evolved in recent years to ensure that contracts are signed before the investor can acquire the financing to build a power plant, but many newly-built power plants in India, particularly those in the private sector, have remained stranded without PPAs, in part due to an unanticipated decline in electricity demand in India following the Great Recession. Long-term contracts for physical delivery of electricity also generate short-run misallocation in dispatch. Conditional on having capacity allocated under a long-term contract, more efficient plants may still be underutilized given the absence of a centralized market-based economic dispatch mechanism. Each state operates the grid in its jurisdiction and self-schedules its contracted power plants once they declare their day-ahead availability.[5] Any residual demand of the state is met through short-term bilateral contracts (i.e. contracts of less than one year) or through one of two power exchanges, both of which transact electricity using only a one-part per-kWh price.[6] Some distribution utilities also enter into banking (or barter) arrangements with other utilities to meet any residual demand for electricity.

Since fixed charges under a long-term PPA are paid on the basis of power plant availability and not generation, the marginal price of one unit of contracted power to the system operator is typically significantly lower than that of one unit of uncontracted power. As a consequence of the prevailing market design, coal-fired power plants that have a higher share of capacity under contract remain relatively indifferent to the price of coal. While changes in coal prices may affect their position in the utility's merit order stack, they are entitled to recover their fixed costs under the PPA. As described in a recent book on the future of the Indian coal industry, "[t]he real market is thus competition for contractual access and not for the coal itself. Such importance of contracts, instead of the commodity, has an analogy in the power sector, where the bidding is for power plants, which is a one-time process, instead of for power. In FY 2018, only 3.5 percent of electricity transacted via markets through power exchanges" (Tongia et al., 2020).

[3] For thermal plants, the capacity charge is calculated as follows:

$$CC_n = AFC \times \frac{n}{12} \times \frac{PAF_n}{NAPAF}$$

PAF_n is the plant availability factor for month n, which is the mean of the daily declared capacities of the plant minus the normative auxiliary consumption expressed as a percentage of its installed capacity. NAPAF is the normative annual plant availability factor, which is typically 85% for thermal plants.

[4] Central government and privately-owned power plants that sell power to multiple states are scheduled and dispatched by Regional Load Dispatch Centres.

[5] The National Load Dispatch Centre manages imbalances closer to real-time by imposing non-market-based penalties for deviations from the schedule through a facility known as the Deviation Settlement Mechanism (DSM).

[6] Renewable energy contracts also consist of a one-part per-unit price. Per-unit prices, which primarily reflect capital costs, are either determined through regulated feed-in tariffs or discovered via auctions. As a result, the marginal "contractual" cost of one unit of electricity from a coal plant can be less than the marginal "contractual" cost of one unit of electricity from a renewable plant. Central government rules mandate than renewable energy "must run" i.e. must be lifted by contracted buyers when it is available.

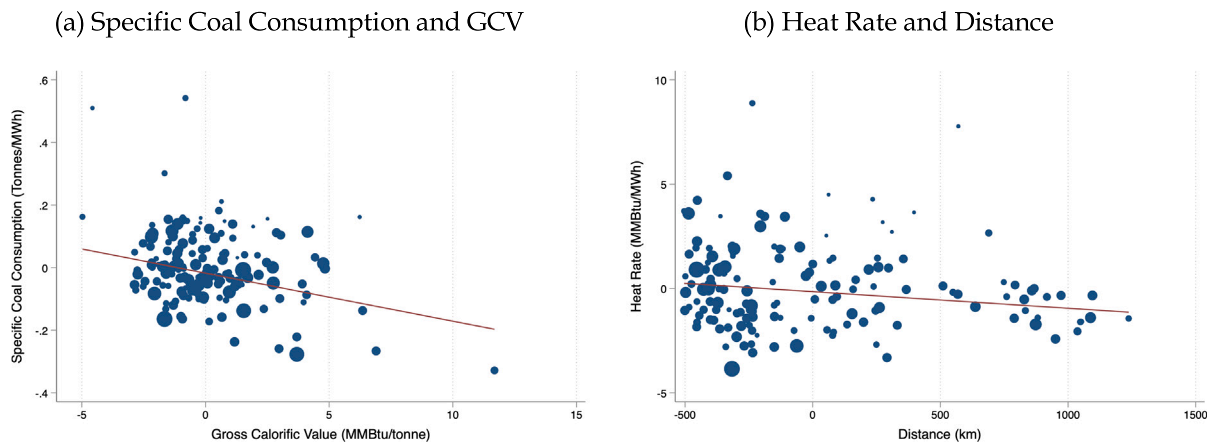


Fig. 6. Correlations of Specific Coal Consumption (Tonnes/MWh) and Gross Calorific Value (MMBtu/tonne), and Heat Rate (MMBtu/MWh) and Coal Transportation Distance (km). (Figure (a) presents the correlation between the average gross calorific value (MMBtu/tonne) of the coal each plant consumes and its specific coal consumption (tonnes/MWh) using data from 2012 until 2020. Figure (b) presents the correlation between the average heat rate (MMBtu/MWh) and the distance (km) that coal is transported by rail before it arrives at the plant using data from 2012 until 2020. Each variable is residualized on month-by-year fixed effects. Each point represents a unique coal plant weighted by its capacity (MW).)

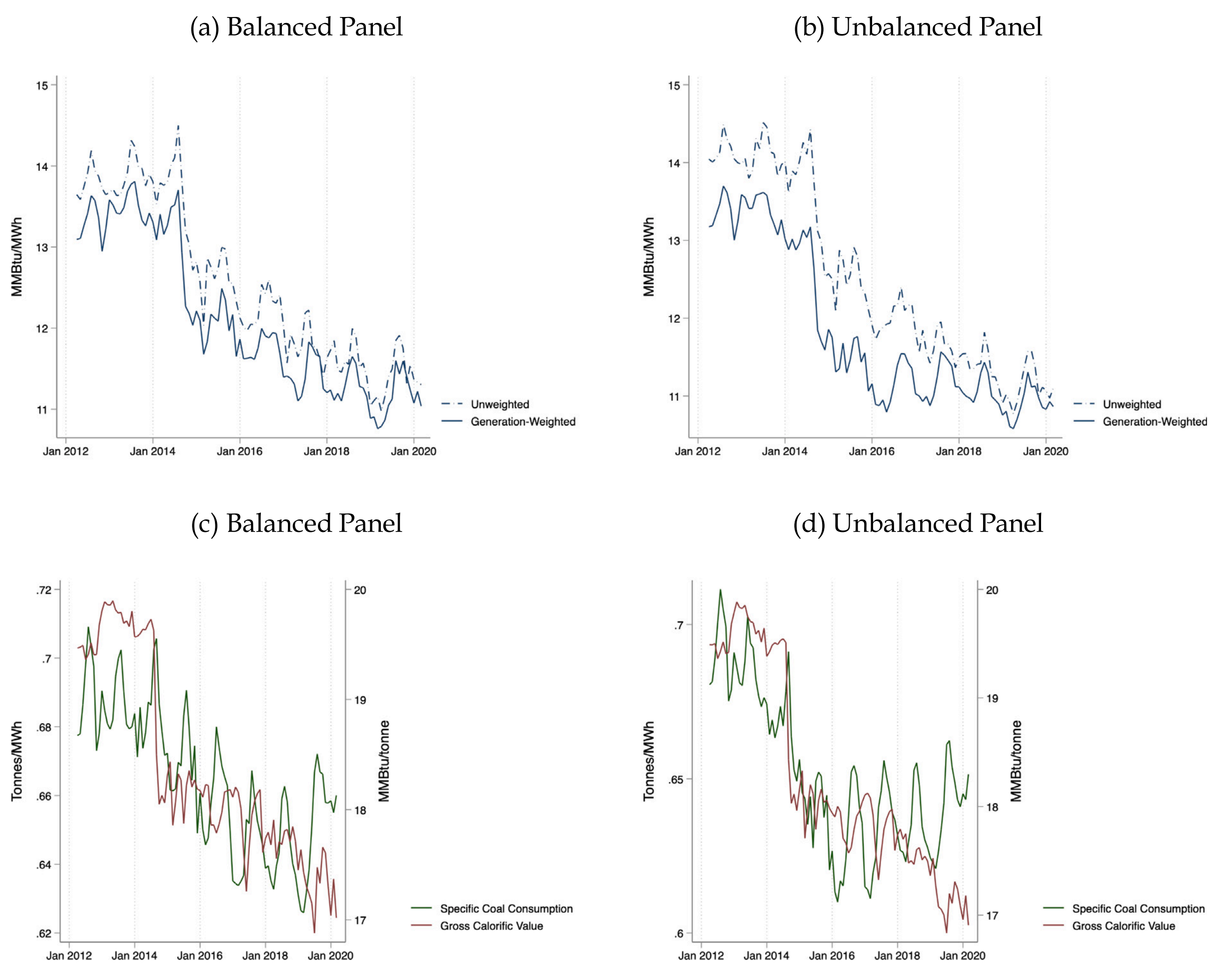
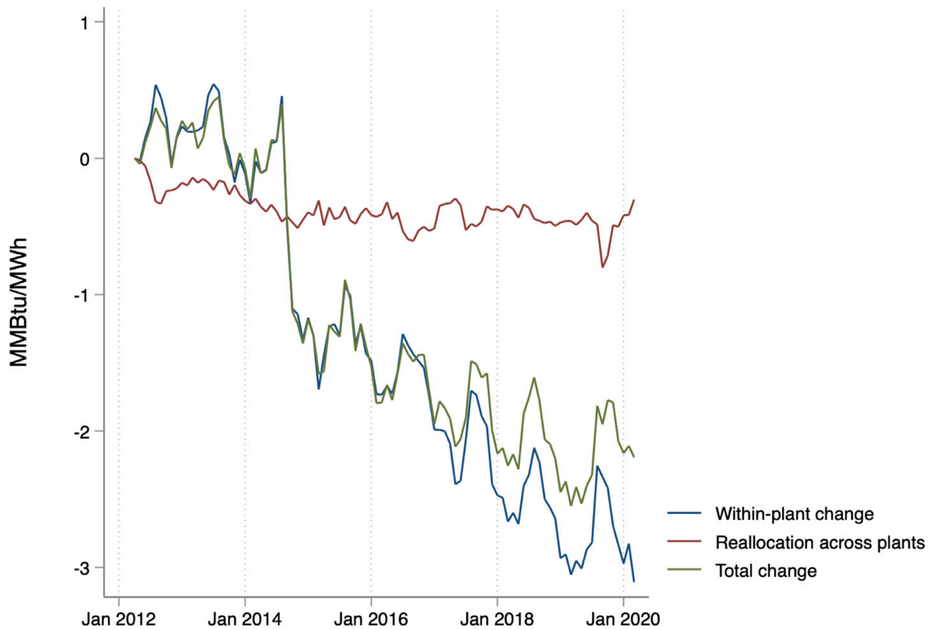


Fig. 7. Coal Plant Efficiency, 2012–2020. (Figures (a) and (b) present unweighted (dashed line) and generation-weighted (solid line) average heat rates (MMBtu/MWh) for each month from 2012 until 2020 using plants in the balanced and unbalanced panels respectively. Figures (c) and (d) present generation-weighted specific coal consumption (tonnes/MWh) on the left axis and gross calorific value (MMBtu/tonne) of the coal received by plants on the right axis.)

1.2. Coal pricing

Coal India Limited (CIL), a central government-owned enterprise and the largest coal mining company in the world, produces more than 80% of domestic coal in India through eight subsidiaries that mine coal in different regions. The subsidiary companies sell the coal to power generation utilities with whom they have long-term contracts, known as Fuel Supply Agreements (FSAs), at prices that are fixed statutorily.

(a) Balanced Panel



(b) Unbalanced Panel

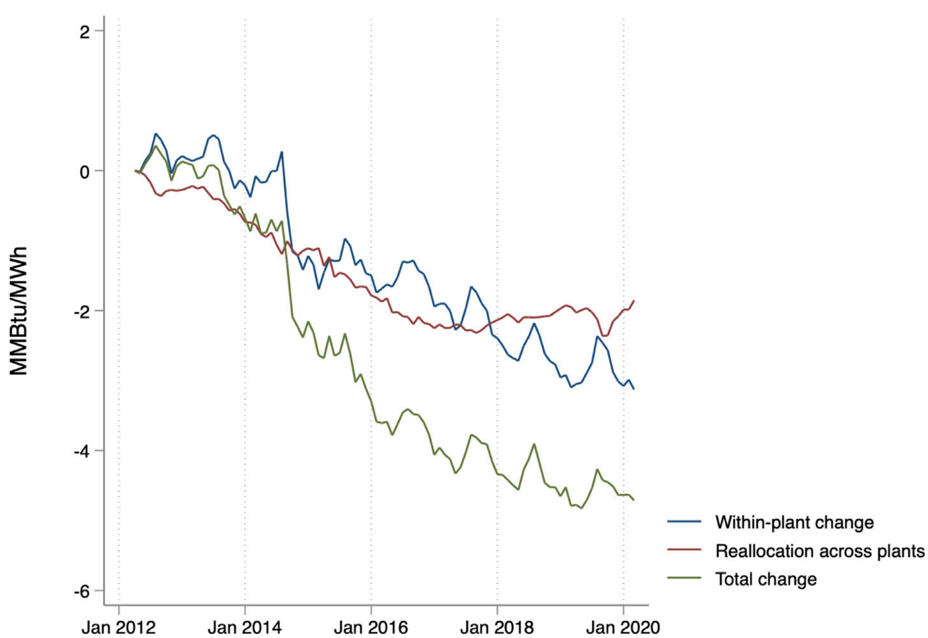


Fig. 8. Decomposition of Changes in Generation-Weighted Coal Plant Efficiency, 2012–2020. (The figures plot the running sums of month-to-month changes in generation-weighted heat rates (green line), within-plant changes in heat rates holding markets shares fixed at the initial level and changes in market shares holding heat rates fixed at the initial level (red line) from 2012 until 2020. Figure (a) restricts the sample to plant that are in the balanced panel.)

These "Run-of-Mine" (ROM) prices are levied on a per tonne (or per metric ton) basis and vary by grade, which represents a specific range of gross calorific value or heat value, measured in kilocalories per kilogram. Table 1 presents an example of a price schedule issued by Coal India in 2018. Coal with a higher gross calorific value burns more efficiently and is therefore more costly. Notified prices are slightly lower for power utilities compared to other coal-consuming industries, and these prices vary modestly across CIL subsidiaries. Coal India, upon receiving approval from the Ministry of Coal, periodically adjusts these grade-wise prices according to the Consumer Price Index (CPI) and the Weighted Price Index (WPI) for non-coking coal, which is the type of coal used for electricity generation. Rail is used as the predominant means of transporting coal to power plants in India. Of the 714.6 million tonnes of coal that were transported to power plants over land in FY 2018, 353.6 million tonnes, or about 50% was transported by rail, 235.17 million tonnes, or 33%, moved by road, and 120.3 million tonnes, or 17% moved by conveyor belt, which primarily serves plants located at the mine-mouth. Prices for transporting commodities by rail

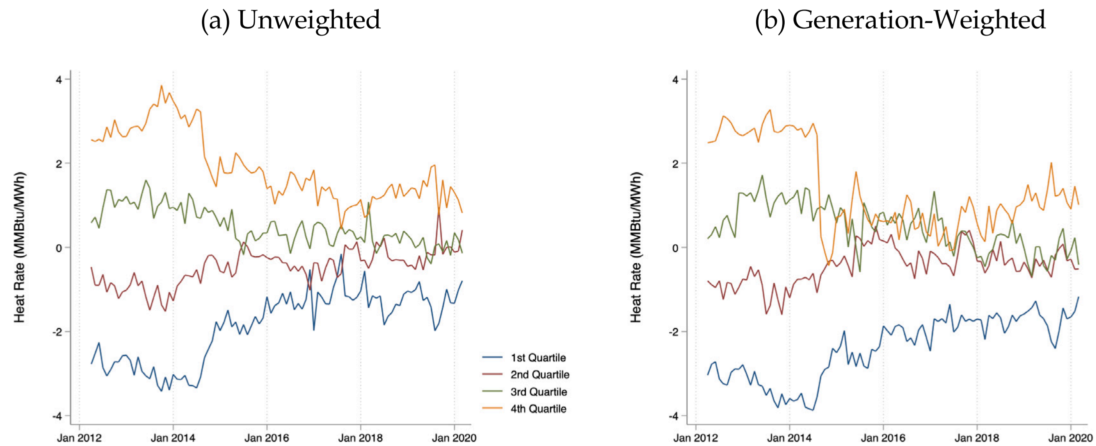


Fig. 9. Monthly Weighted Average Heat Rate (MMBtu/MWh) by Quartiles of Heat Rate Distribution in FY 2012–FY 2013. (The figure plots the monthly heat rates (MMBtu/MWh) by quartiles of the distribution of heat rates of coal plants in FY 2012 and FY 2013. The average heat rate in each month is residualized on month-by-year fixed effects. Figure (b) weights heat rates by the plant's share of total generation in the quartile. The sample is restricted to the balanced panel.)

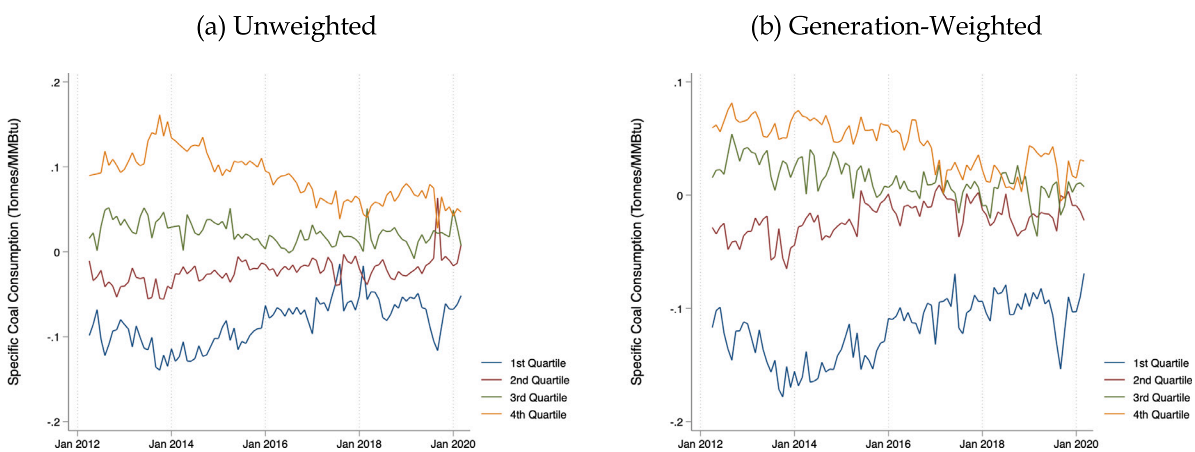


Fig. 10. Monthly Weighted Average Specific Coal Consumption (Tonnes/MWh) by Quartiles of the Heat Rate Distribution in FY 2012–FY 2013. (The figure plots the monthly specific coal consumption (tonnes/MWh) by quartiles of the distribution of heat rates of coal plants in FY 2012 and FY 2013. The average specific coal consumption in each month is residualized on month-by-year fixed effects. Figure (b) weights specific coal consumption by the plant's share of total generation in the quartile. The sample is restricted to the balanced panel.)

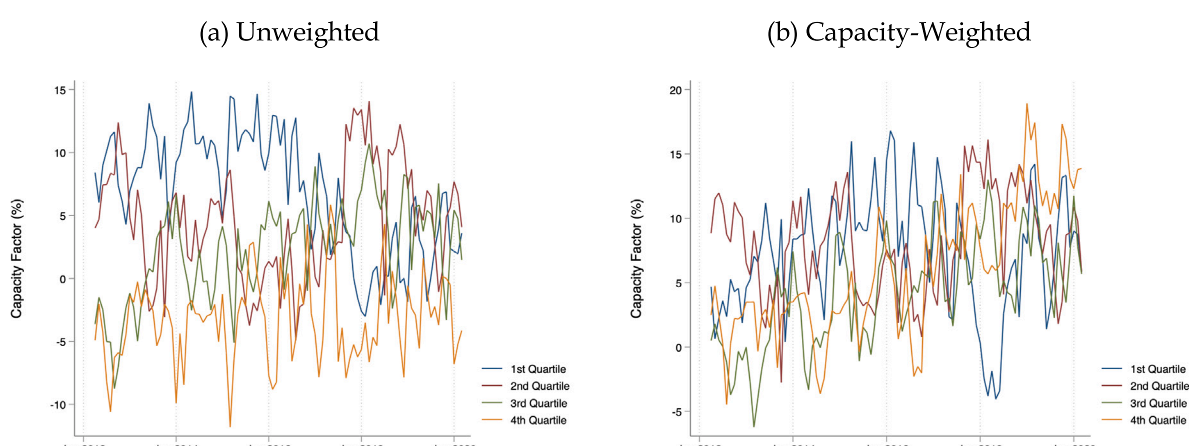


Fig. 11. Monthly Weighted Average Capacity Utilization (%) by Quartiles of the Heat Rate Distribution in FY 2012–FY 2013. (The figure plots monthly capacity utilization rates (%) by quartiles of the distribution of heat rates of coal plants in FY 2012 and FY 2013. The average capacity utilization rate in each month is residualized on month-by-year fixed effects. Figure (b) weights utilization rates by the plant's share of total capacity in the quartile. The sample is restricted to the balanced panel.)

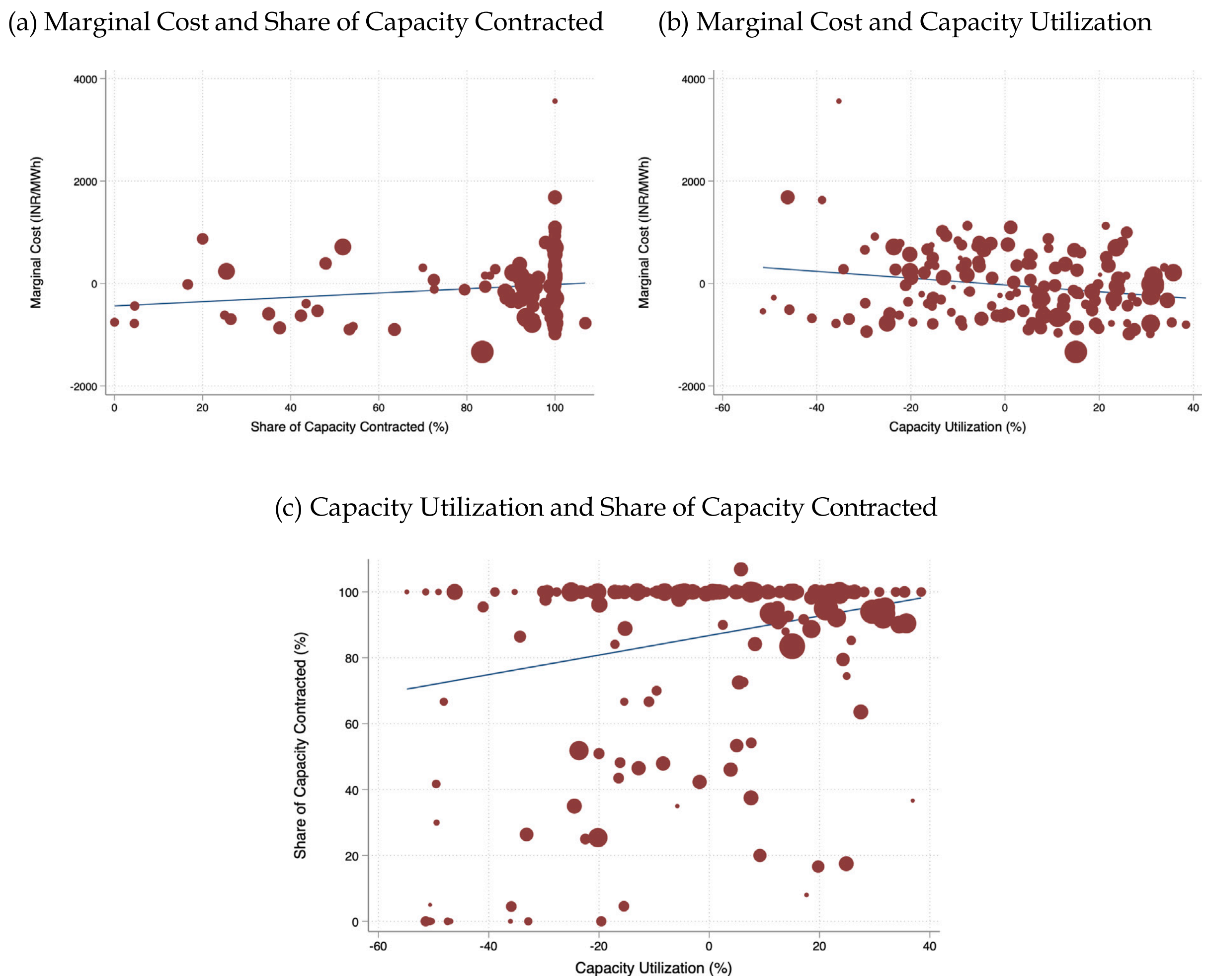


Fig. 12. Pair-Wise Correlations of Share of Capacity Contracted (%), Marginal Cost (INR/MWh) and Capacity Utilization (%). (Figure (a) presents the correlation between marginal cost (INR/MWh) and share of capacity contracted (%). Figure (b) presents the correlation between marginal cost (INR/MWh) and capacity utilization (%). Figure (c) presents the correlation between share of capacity contracted (%) and capacity utilization (%). Marginal cost and capacity utilization are residualized on month-by-year fixed effects. Each point is a unique coal plant weighted by its capacity (MW).)

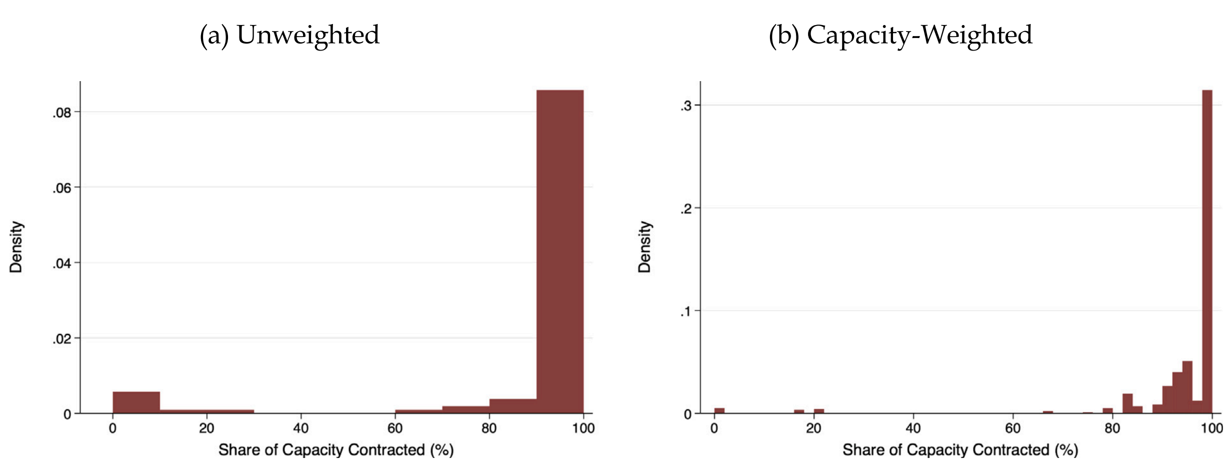


Fig. 13. Share of Capacity Contracted (%), Balanced Panel. (The figure presents histograms of the unweighted and capacity-weighted share of capacity allocated under long-term contracts in FY 2020 for each coal plant in the balanced panel.)

are fixed statutorily by the Ministry of Railways and vary by the type of commodity and by ranges of distance.

As shown in Fig. 3, there are two types of taxes on coal production: ad-valorem taxes and flat taxes. Royalties are an example of an ad-valorem tax as they are levied as a proportion of the coal price, whereas other taxes are applied lumpsum, such as the “Clean Energy Cess”, which is a tax of INR 400 (USD 5.45) that is currently levied on every tonne of coal produced domestically or imported. Ad-valorem taxes are applied as a percentage of the per-tonne price of coal and vary in absolute terms by the grade of coal, while flat taxes are applied uniformly

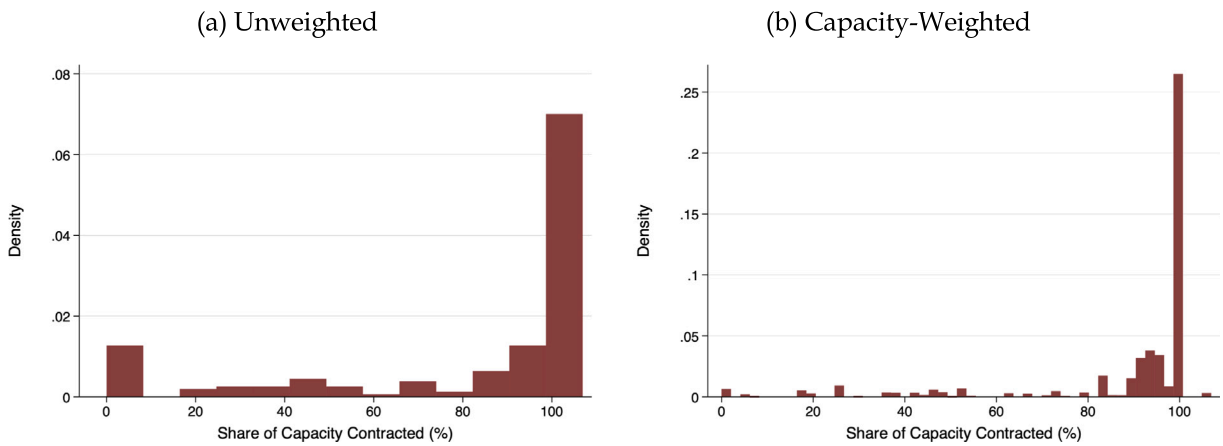


Fig. 14. Share of Capacity Contracted (%), Unbalanced Panel. (The figure presents histograms of the unweighted and capacity-weighted share of capacity allocated under long-term contracts in FY 2020 for each coal plant in the unbalanced panel.)

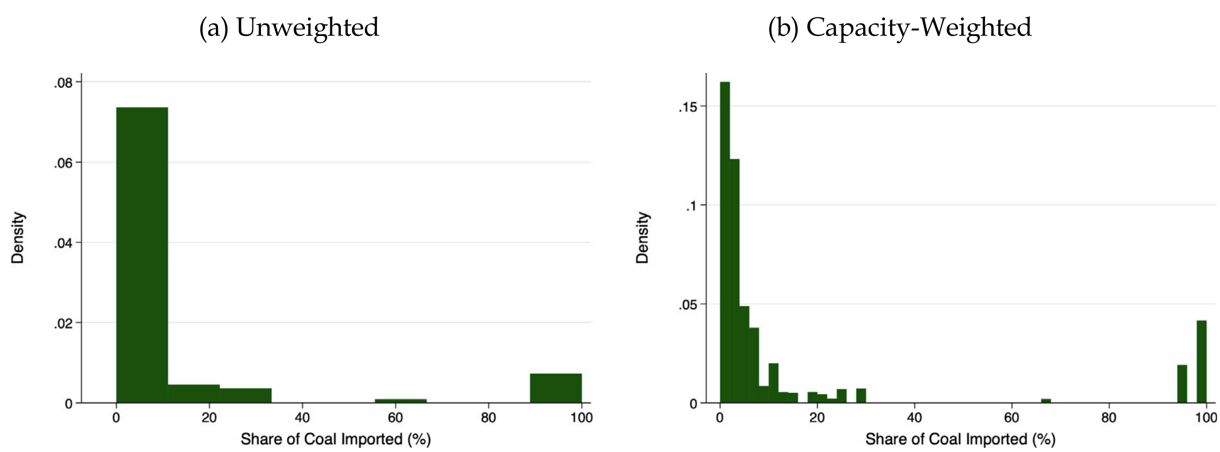


Fig. 15. Share of Coal Imported (%), Balanced Panel. (The figure presents histograms of the unweighted and capacity-weighted share of imported coal in FY 2020 for each coal plant in the balanced panel.)

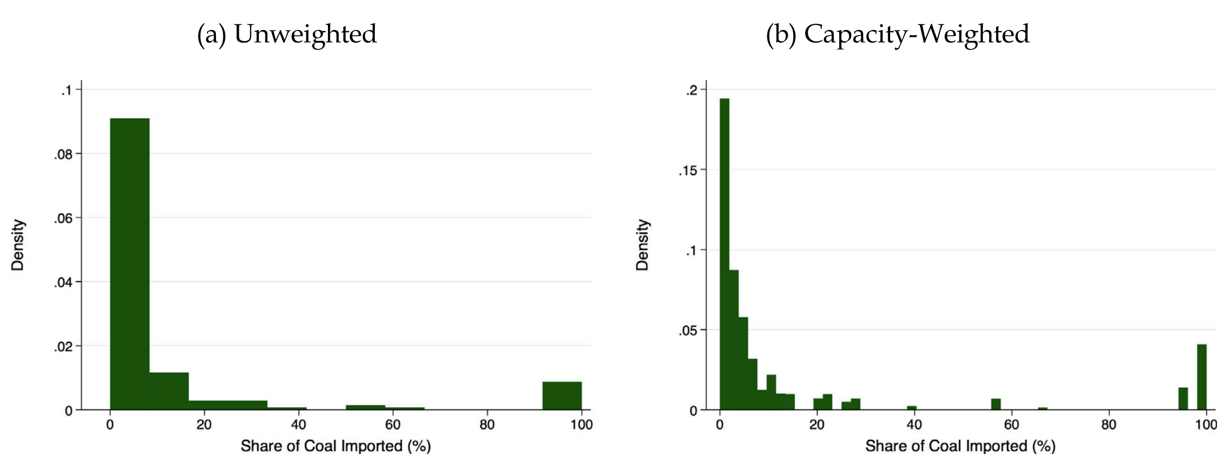


Fig. 16. Share of Coal Imported (%), Unbalanced Panel. (The figure presents histograms of the unweighted and capacity-weighted share of imported coal in FY 2020 for each coal plant in the unbalanced panel.)

on all grades. This difference implies that, all else equal, coal plants that consume lower grades of coal will be disproportionately impacted by a flat tax given that they consume more coal to generate the same amount of electricity. Flat taxes may be large enough to affect the position of these plants in the merit order and incentivize distribution utilities to reallocate production from plants that consume lower grade coal to plants that consume higher grade coal. As illustrated in Fig. 6(a), the average gross calorific value of coal that a plant consumes is correlated

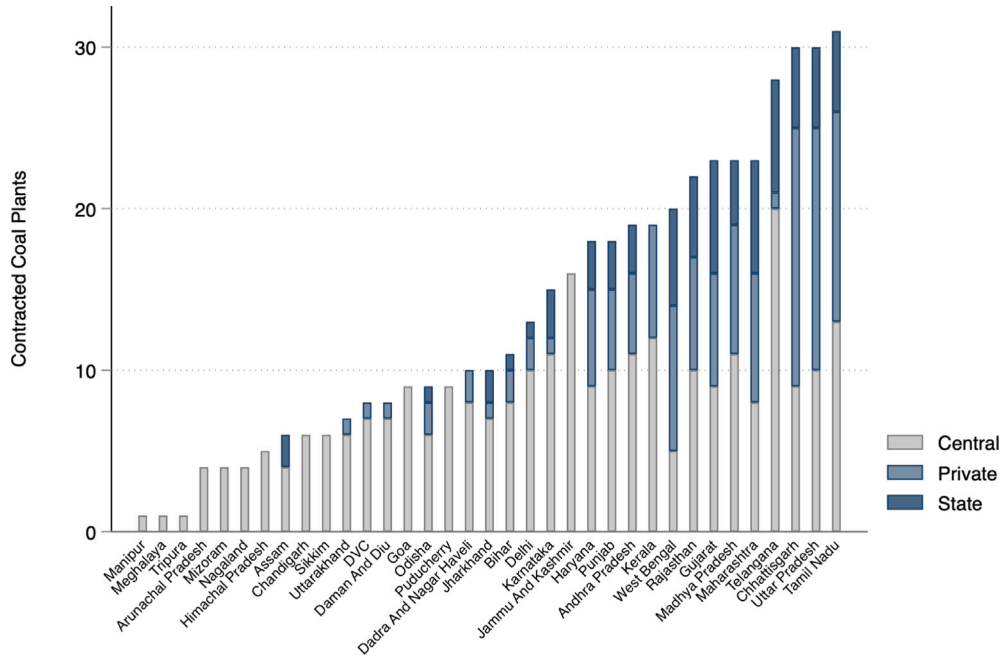


Fig. 17. Number of contracted coal plants by state. (Each bar represents the number of coal plants contracted with a specific state. The bars are stacked by ownership type.)

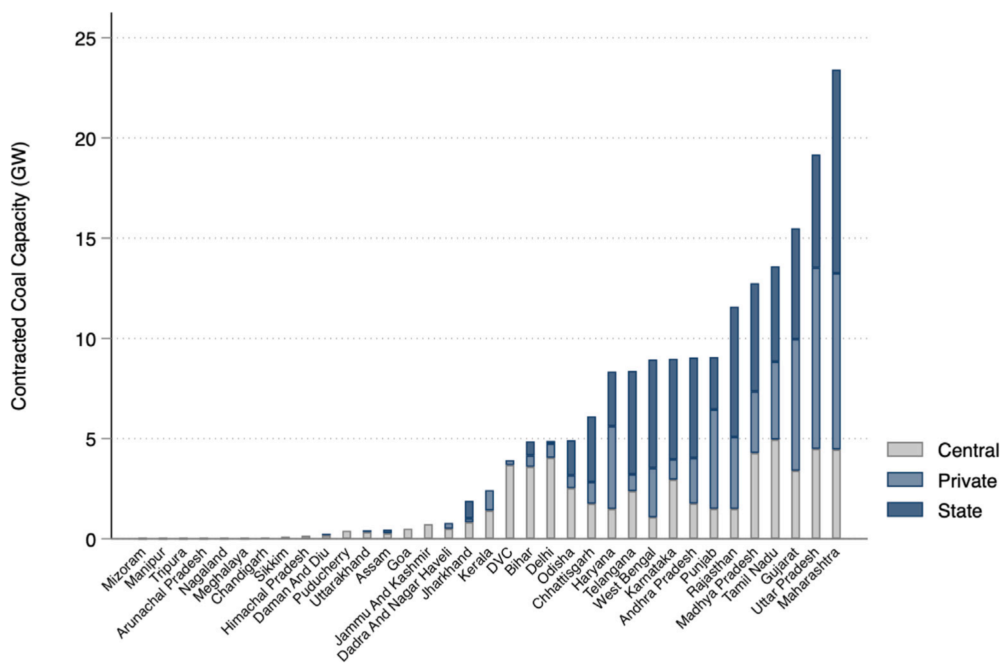


Fig. 18. Contracted coal capacity by state. (Each bar represents the total contracted coal capacity of a specific state. The bars are stacked by ownership type.)

with its thermal efficiency (as measured by tonnes consumed per MWh generated), which implies that flat taxes on coal provide an incentive to reallocate output to plants that are more efficient overall.[7]

Furthermore, as shown in Fig. 6(b), the correlation between heat rates (i.e. heat input per unit of electricity output), a standard measure of thermal efficiency, and the average distance coal is transported by rail before arriving at the plant is relatively weaker, which implies that there is lesser scope for flat taxes to induce output reallocation from less efficient plants with lower transportation costs to more efficient plants with higher transportation costs. Since regulated freight prices also do not vary by grade, all else equal, changes in freight prices have a similar disproportionate impact on plants that consume lower grades of coal. As a consequence, for low grade coal, taxes and freight prices, which have steadily risen in the last decade, are now roughly equivalent to the ROM or base price of coal itself (see Fig. 4). In theory,

[7] Plants that receive coal through long-term FSAs with Coal India have limited control over the quality of coal they receive, even though the annual contracted quantity (ACQ) and grade are specified in the FSA.

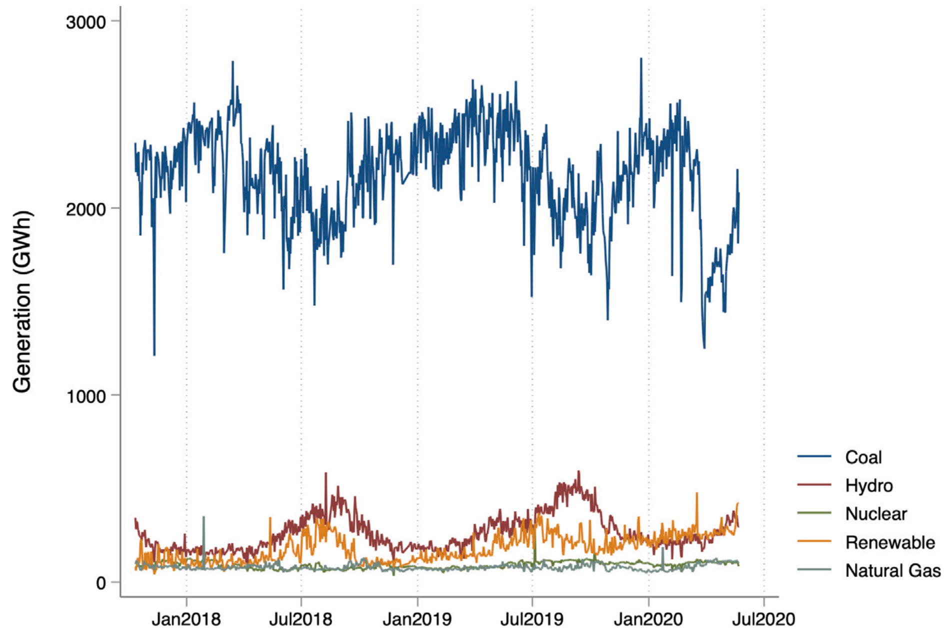


Fig. 19. Electricity Generation by Source. (The figure displays daily electricity generation by type from October 2017 to January 2020 using data scraped from the MERIT web application of the Ministry of Power.)

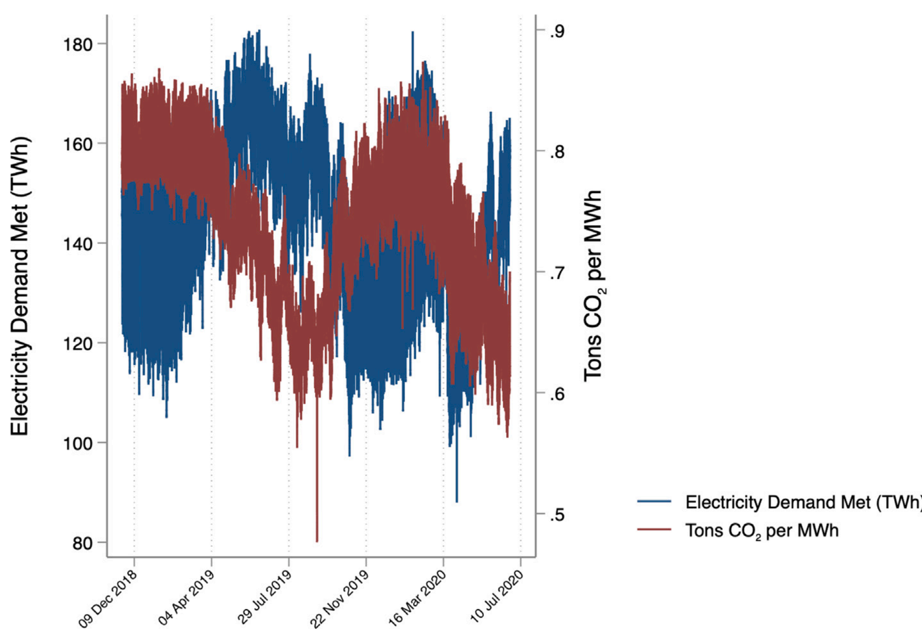


Fig. 20. Electricity Demand and Emissions Intensity. (The figure displays daily electricity demand met and tons CO_2 per MWh from December 2018 to January 2020 using data scraped from the Electricity and Carbon Tracker web application of the Centre for Social and Economic Progress in India.)

an increase in coal prices will make less efficient coal-fired generation relatively more costly, which could induce some reallocation from less to more efficient plants within a utility's merit order stack. However, we would expect greater output reallocation if the electricity market were cleared through a centralized market-based economic dispatch mechanism in which all power plants participated. The possibility of greater output reallocation across plants would enable more emissions abatement at no additional cost. While the objective of this paper is not to quantify the effect of an increase in the delivered price of coal on overall misallocation in the power sector, I illustrate the mechanisms for reallocation of output in response to such price shocks through two numerical examples in the Appendix.

2. Data and summary statistics

I collect detailed power plant operations data from the Central Electricity Authority, a division of the Ministry of Power. The data were scraped from monthly plant- and unit-level generation reports, monthly plant-level coal consumption reports, daily plant-level coal stock reports and daily unit-level outage reports from 2012 until 2020.

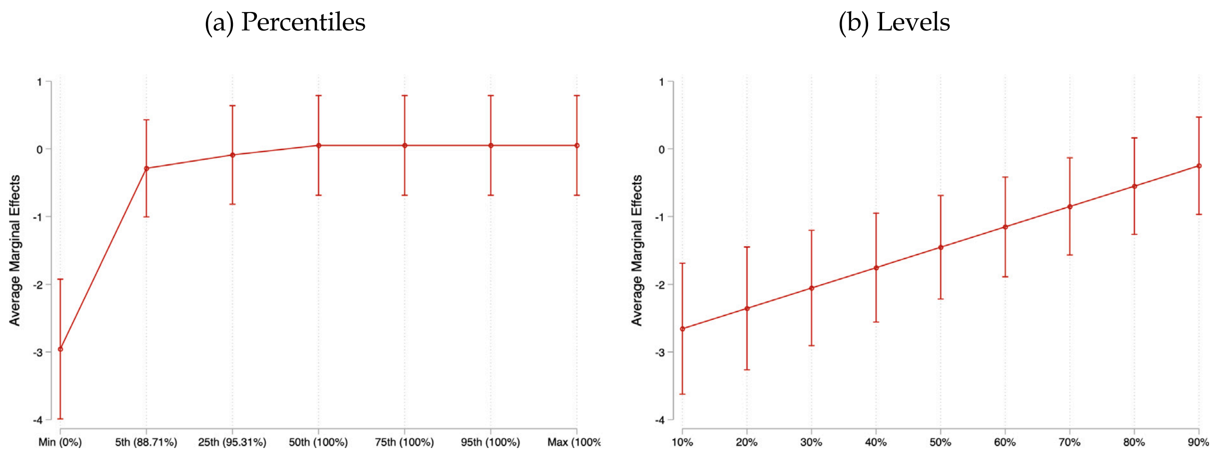


Fig. 21. Average Marginal Effects, Balanced Panel. (The figure presents point estimates and 95% confidence intervals of the average marginal effects of the log of delivered coal prices on the log of utilization rates at different values over the distribution of the share of capacity contracted (%) in the balanced panel. The specification used is the same as the model estimated in column (5) of Table 9.)

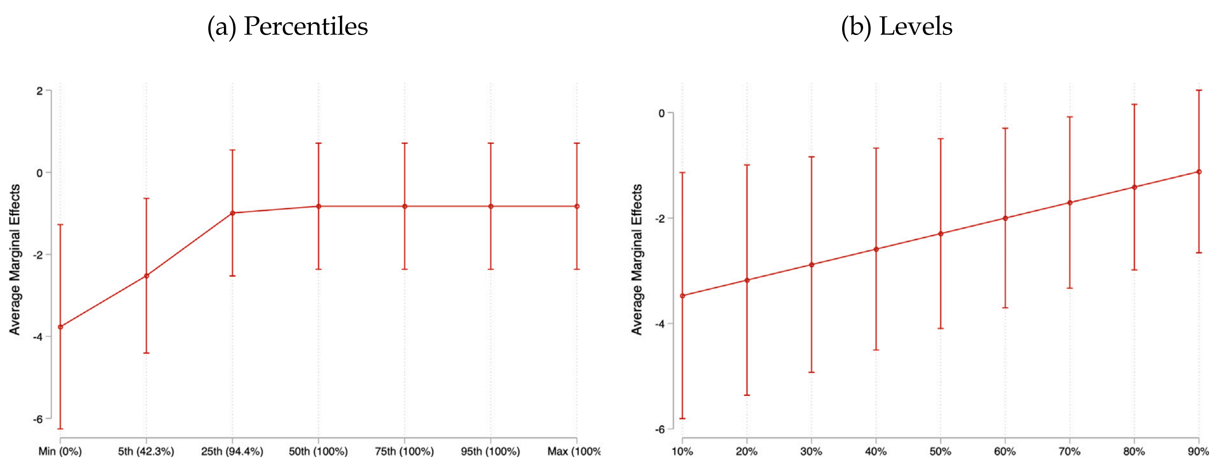


Fig. 22. Average Marginal Effects, Unbalanced Panel. (The figure presents point estimates and 95% confidence intervals of the average marginal effects of the log of delivered coal prices on the log of utilization rates at different values over the distribution of the share of capacity contracted (%) in the unbalanced panel. The specification used is the same as the model estimated in column (7) of Table 14.)

Table 1
Coal India notified prices, 2018.

Grade	Calorific value range (kcal/kg)	Power utilities (INR/tonne)	Other sectors (INR/tonne)
G2	6700–7000	3288	3288
G3	6400–6700	3144	3144
G4	6100–6400	3000	3000
G5	5800–6100	2737	2737
G6	5500–5800	2317	2524
G7	5200–5500	1926	2311
G8	4900–5200	1465	1757
G9	4600–4900	1140	1368
G10	4300–4600	1024	1228
G11	4000–4300	955	1145
G12	3700–4000	886	1063
G13	3400–3700	817	980
G14	3100–3400	748	897
G15	2800–3100	590	708
G16	2500–2800	504	604
G17	2200–2500	447	536

This table provides an example of a regulated price schedule issued by Coal India in 2018 for different grades of non-coking coal. These notified prices apply to all coal supplied through long-term contracts or Fuel Supply Agreements.

Table 2
Plant characteristics by quartiles of the distribution of heat rates in FY 2012–FY 2013.

	1st		2nd		3rd		4th		Total	
	Mean	SD	Mean	SD	Mean	SD	Mean	SD	Mean	SD
Capacity (MW)	1006.2	906.3	1122.08	711.42	1058.23	683.81	1098.52	830.99	1070.59	778.49
Age of Oldest Unit (Years)	10.61	10.51	13.87	12.89	19.93	14.42	22.83	16.06	16.75	14.24
Age of Newest Unit (Years)	6	8.92	4.67	8.18	6.67	10.93	6.16	12.94	5.87	10.26
Share of Capacity Contracted (%)	93.45	17.8	95.1	20.33	97.59	5.6	95.17	16.31	95.31	15.86
Ownership										
Private Sector	.64	.49	.08	.28	.13	.34	.21	.41	.27	.45
State Sector	.2	.41	.67	.48	.58	.5	.5	.51	.48	.5
Central Sector	.16	.37	.25	.44	.29	.46	.29	.46	.25	.43
Source of Coal										
Domestic/Blended	.68	.48	.96	.2	1	0	1	0	.91	.29
Imported Only	.32	.48	.04	.2	0	0	0	0	.09	.29
Boiler Design										
Pulverized Coal Boiler	.96	.2	.92	.28	.96	.2	.83	.38	.92	.28
CFBC Boiler	0	0	0	0	.04	.2	.17	.38	.05	.22
Supercritical Boiler	.04	.2	.08	.28	0	0	0	0	.03	.17
Number of Plants	25		24		24		24		97	

This table summarizes the characteristics of coal-fired power plants in the balanced panel by quartiles of the distribution of heat rates in FY 2012 and FY 2013 with the first quartile comprising the most efficient plants.

Table 3
Monthly summary statistics, FY 2012–FY 2019.

	Mean (1)	SD (2)	5% (3)	25% (4)	50% (5)	75% (6)	95% (7)
Panel A: Balanced Panel							
Capacity (MW)	1001.01	787.09	90	450	870	1340	2340
Utilization Rate (%)	68.61	28.44	0	58.49	78.1	89.56	97.92
Heat Rate (MMBtu/MWh)	13.65	2.44	10.72	12.06	13.39	15.11	18.11
Specific Coal Consumption (Tonnes/MWh)	.71	.12	.53	.64	.71	.78	.89
Gross Calorific Value (MMBtu/tonne)	19.17	2.67	16.24	17.38	18.66	20.54	23.09
Distance (km)	558.77	486.4	19.5	155.57	415.82	870.99	1515.79
Share of Coal Imported (%)	12.04	24.02	0	0	0	15.09	100
Age of Oldest Unit (Years)	16.43	14.32	.17	2	17.21	28.17	44.33
Share of Capacity Contracted (%)	90.66	25.53	0	97.87	100	100	100
Actual Delivered Price (INR/MMBtu)	133.05	41.9	66.53	104.77	128.25	155.23	229.1
Actual Coal Price (INR/MMBtu)	92.76	32.16	58.87	65.24	84.11	109.91	151.17
Actual Freight Price (INR/MMBtu)	40.29	31.14	5.11	12.51	30.65	59.71	98.54
Predicted Delivered Price (INR/MMBtu)	111.36	37.45	73.09	80.96	100.5	127.33	191.45
Predicted Coal Price (INR/MMBtu)	69.48	21.91	59.77	61.14	62.65	69.67	87.42
Predicted Freight Price (INR/MMBtu)	41.83	33.1	9.45	15.94	29.69	60.03	113.18
Number of Observations (Plant × Month)	10 078						
Panel B: Unbalanced Panel							
Capacity (MW)	772.82	669.54	63	300	600	1000	2100
Utilization Rate (%)	46.13	37.14	0	3.5	50.86	80.84	96.75
Heat Rate (MMBtu/MWh)	14	2.84	10.72	12.14	13.57	15.32	18.85
Specific Coal Consumption (Tonnes/MWh)	.73	.15	.53	.65	.72	.8	.97
Gross Calorific Value (MMBtu/tonne)	18.43	2.93	14.91	16.24	18.39	19.9	23.09
Distance (km)	582.84	479.1	30.47	195.09	462.07	888.24	1573
Share of Coal Imported (%)	10.95	23.16	0	0	0	13.59	100
Age of Oldest Unit (Years)	11.37	14.91	0	0	2	23.42	40.5
Share of Capacity Contracted (%)	82.74	30.57	4.5	84.1	100	100	100
Actual Delivered Price (INR/MMBtu)	141.15	46.43	69.03	107.86	137.18	168.83	229.22
Actual Coal Price (INR/MMBtu)	95.2	33.01	58.87	67.56	84.11	116.79	151.17
Actual Freight Price (INR/MMBtu)	45.94	34.08	5.73	17.12	41.19	69.41	114.19
Predicted Delivered Price (INR/MMBtu)	121.2	43.44	73.75	90.11	108.77	146.42	208.08
Predicted Coal Price (INR/MMBtu)	76.54	23.41	59.99	62.16	69.21	82.56	116.37
Predicted Freight Price (INR/MMBtu)	44.26	34.77	9.98	16.56	34.6	62.71	119.13
Number of Observations (Plant × Month)	15 033						

The table presents summary statistics at the plant-month level separately for plants in the balanced panel (Panel A) and in the unbalanced panel (Panel B).

In addition, I collect scraped data from the Ministry of Power's MERIT web application, which was launched in November 2017, that provides detailed plant-level declared availability (MWh), scheduled energy (MWh), fixed and variable charges (INR/kWh) and contractual capacity allocation (MW) to states as well as energy purchased through short-term bilaterals and the power exchanges (MWh) on a daily basis. The contractual capacity allocation to individual states typically remains fixed at the level specified in the PPA, regardless of whether

Table 4
Annual summary statistics, FY 2012–FY 2019.

	Mean (1)	SD (2)	5% (3)	25% (4)	50% (5)	75% (6)	95% (7)
Panel A: Balanced Panel							
Capacity (MW)	1046.66	821.86	90	470	920	1340	2600
Utilization Rate (%)	66.42	22.88	19.91	55.36	71.84	83.67	91.96
Heat Rate (MMBtu/MWh)	13.74	2.31	10.13	12.15	13.47	15.21	17.6
Specific Coal Consumption (Tonnes/MWh)	.72	.12	.49	.65	.72	.8	.91
Gross Calorific Value (MMBtu/tonne)	19.2	2.63	16.24	17.38	18.77	20.52	23.1
Distance (km)	536.12	463.39	20.04	174.67	395.31	840.98	1453.66
Share of Coal Imported (%)	14.54	26.84	0	0	4.54	12.81	100
Age of Oldest Unit (Years)	16.41	14.28	0	2	17	28	45
Share of Capacity Contracted (%)	90.66	25.53	0	97.87	100	100	100
Actual Delivered Price (INR/MMBtu)	142.22	42.15	74.63	113.94	138.24	164.97	231.74
Actual Coal Price (INR/MMBtu)	102.94	33.11	67.36	77.29	95.64	120.38	158.02
Actual Freight Price (INR/MMBtu)	39.28	30.43	5.66	15.98	28.09	56.38	100.78
Predicted Delivered Price (INR/MMBtu)	122.65	37.77	82.25	92.99	110.45	139.42	197.1
Predicted Coal Price (INR/MMBtu)	82.1	22.16	67.7	70.6	77.92	84.45	100.18
Predicted Freight Price (INR/MMBtu)	40.52	32.07	9.16	15.44	28.77	58.15	109.64
Number of Observations (Plant × Year)	840						
Panel B: Unbalanced Panel							
Capacity (MW)	811.93	699.95	90	330	630	1050	2340
Utilization Rate (%)	47.84	31.78	0	17.69	54.57	73.97	91.1
Heat Rate (MMBtu/MWh)	13.69	2.82	9.25	11.78	13.38	15.38	18.05
Specific Coal Consumption (Tonnes/MWh)	.72	.14	.5	.64	.71	.8	.93
Gross Calorific Value (MMBtu/tonne)	18.49	2.85	14.93	16.24	18.26	20.09	23.09
Distance (km)	547.63	453.75	38.25	210.69	441.45	810.79	1518.91
Share of Coal Imported (%)	14.67	27.8	0	0	3.26	12.88	100
Age of Oldest Unit (Years)	11.55	15.11	−1	0	2	24	42
Share of Capacity Contracted (%)	82.74	30.57	4.5	84.1	100	100	100
Actual Delivered Price (INR/MMBtu)	145.69	45.31	81.13	113.61	141.57	176.01	231.74
Actual Coal Price (INR/MMBtu)	101.65	32.8	68.08	75.84	92.23	118.34	157.82
Actual Freight Price (INR/MMBtu)	44.04	33.02	6.06	18.63	36.55	62.33	105.21
Predicted Delivered Price (INR/MMBtu)	128.93	42.45	83.2	95.65	114.97	151.68	215.24
Predicted Coal Price (INR/MMBtu)	84.84	22.28	68.07	71.43	78.7	88.58	116.37
Predicted Freight Price (INR/MMBtu)	43.49	33.91	9.67	16.04	34.4	62.39	116.96
Number of Observations (Plant × Year)	1296						

The table presents summary statistics at the plant-year level separately for plants in the balanced panel (Panel A) and in the unbalanced panel (Panel B).

Table 5
Average gross calorific value (MMBtu/tonne) on plant characteristics, FY 2015.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capacity (MW)	0.000118 (0.000284)							
Specific Coal Consumption (Tonnes/MWh)		−3.438* (1.957)						
Share of Capacity Contracted (%)			0.00320 (0.00612)					
Age of Oldest Unit (Months)				−0.000459 (0.00107)				
Central Sector					0.577 (0.493)			
Private Sector					0.509 (0.424)			
CFBC Boiler						0.0924 (0.403)		
Supercritical Boiler						2.078** (0.803)		
Share of Imported Coal (%)								−0.0312 (0.0314)
Constant	17.57*** (0.332)	20.30*** (1.441)	17.41*** (0.580)	17.82*** (0.286)	17.42*** (0.287)	17.65*** (0.211)	17.70*** (0.530)	17.94*** (0.241)
Observations	96	88	96	95	96	96	96	88
State Dummies							✓	
R^2	0.003	0.028	0.002	0.002	0.021	0.025	0.365	0.017

This table presents the results of a set of univariate regressions of average gross calorific value of coal received on plant characteristics in FY 2015. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$

Table 6
Average distance (km) on plant characteristics, FY 2015.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capacity (MW)	−0.0749*							
	(0.0402)							
Specific Coal Consumption (Tonnes/MWh)		−1234.2**						
		(493.9)						
Share of Capacity Contracted (%)			1.609					
			(1.116)					
Age of Oldest Unit (Months)				−0.227				
				(0.243)				
Central Sector					−247.0**			
					(100.3)			
Private Sector					−13.47			
					(115.6)			
CFBC Boiler						245.3***		
						(82.17)		
Supercritical Boiler						297.6		
						(388.2)		
Share of Imported Coal (%)								9.826
								(6.448)
Constant	592.7***	1407.4***	355.2***	565.3***	574.9***	484.9***	577.3***	469.0***
	(68.28)	(380.8)	(94.49)	(79.90)	(71.02)	(49.84)	(58.71)	(51.60)
Observations	92	88	92	92	92	92	92	88
State Dummies							✓	
R^2	0.018	0.063	0.005	0.008	0.058	0.027	0.755	0.029

This table presents the results of a set of univariate regressions of the average distance (km) on plant characteristics in FY 2015. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$

the allocation was the outcome of competitive bidding or a negotiation process.[8] There are 658 thermal, hydro and nuclear plants in the MERIT database that have some amount of capacity allocated to one or more of 34 states and union territories through long-term bilateral contracts.[9]

I collect data on coal shipments by rail from the Freight Operations Information System (FOIS) database maintained by the Centre for Railway Information Systems (CRIS), an arm of the Ministry of Railways. This database provides detailed information on the consignor (i.e. plant owner), the consignee (i.e. coal company), departure and arrival times, weight of the consignment, grade of coal being dispatched and total freight charges from 2012 until 2020. A noteworthy benefit of having access to the FOIS database is that the per tonne cost of transportation can be computed from the billing data directly. On the other hand, fuel costs need to be inferred from the grade of coal received by the plant, the coal company supplying the coal and notified price schedules. An important caveat, however, is that the grade of imported coal that is transported to plants by rail is not provided in the FOIS database. I compute the weighted average gross calorific value of the coal each plant receives by rail in every month and combine these data with the plant's monthly generation (GWh) and coal consumption (tonnes) to estimate heat rates (MMBtu/MWh). Thermal plants that have lower heat rates are more efficient in converting the energy stored in coal into electricity during combustion. Mathematically, heat rates are computed as follows:

$$\text{Heat Rate (MMBtu/MWh)} = \frac{\text{Coal Consumption (Tonnes)}}{\text{Electricity Generation (MWh)}} \times \text{Gross Calorific Value (MMBtu/Tonne)}$$

I assemble regulated grade-wise domestic coal prices as well as ad-valorem and flat taxes from tariff orders issued by all Coal India subsidiaries and the Singareni Collieries Company Limited (SCCL), another central government-owned coal mining company that accounts for 9.2% of domestic coal production, from 2012 until 2020. Notified freight prices for coal transportation are collected from tariff orders issued by the Ministry of Railways. I do not observe prices of coal procured via imports, captive coal blocks or Coal India's "E-Auction" spot market. Since captive coal blocks and the Coal India spot market collectively account for a small fraction of domestic coal supplied to the power sector, I assign notified Coal India prices that apply to coal procured through traditional long-term fuel supply contracts to domestic coal procured through all other sources. I exclude shipments of imported coal from the analysis altogether since delivered prices of imported coal are likely to be significantly higher than domestic coal, reflecting both a higher average gross calorific value of the coal itself and higher shipping costs. Fig. 5 illustrates the amount of coal that was procured nationally through each of these mechanisms from 2013 until 2020. Following the controversial decision of the Supreme Court of India to cancel all licenses for operating captive coal blocks in August 2014 on the grounds that all coal block allocations made between 1993 and 2010 were influenced by corruption and were therefore illegal, the average gross calorific value of coal declined precipitously as power producers that lost access to their coal blocks were compelled to procure lower-grade coal through short-term contracts, known as bridge linkages, with Coal India.

As illustrated in Fig. 7(a), there has been a dramatic improvement in the thermal efficiency of coal-fired power plants in recent years. The underlying sample is restricted to the balanced panel of coal plants that were operational for at least 93 of the 96 months between FY 2012 and FY 2019. The reduction in specific coal consumption (i.e. tonnes of coal consumed per MWh of electricity generated) as seen in Fig. 7(c) suggests that plants were able to improve their efficiency despite a significant decline in the quality of coal that they were receiving. The decline in heat value was driven both by the 2014 Supreme Court decision and by import substitution as production of cheaper low-grade domestic coal increased during this period. Domestic coal has a high

[8] Since the Regional and National Load Dispatch Centres are responsible for balancing the grid at the intraregional and interregional levels respectively, they may modify the capacity allocation of central or privately-owned plants that are contracted with multiple states, but those changes are small and infrequent. For the analysis, I validate the actual capacity allocation figures with 2018–19 State Electricity Regulatory Commission tariff orders.

[9] In some cases, PPAs are signed directly with state-owned or private companies. For example, the Damodar Valley Corporation (DVC) is a central government-owned enterprise that operates generation assets and the distribution network in parts of West Bengal and Jharkhand. Private or state-owned companies that use captive power such as Essar Steel or the Indian Railways also have long-term PPAs with power plants.

Table 7
Share of capacity contracted (%) on plant characteristics, FY 2015.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capacity (MW)	0.00726**							
	(0.00343)							
Specific Coal Consumption (Tonnes/MWh)		7.819						
		(10.19)						
Gross Calorific Value (MMBtu/tonne)			0.591					
			(1.197)					
Age of Oldest Unit (Months)				0.0259*				
				(0.0154)				
Central Sector					−4.966***			
					(1.115)			
Private Sector					−28.30***			
					(8.813)			
CFBC Boiler						−30.34*		
						(15.67)		
Supercritical Boiler						3.028		
						(3.003)		
Share of Imported Coal (%)								0.0635
								(0.0544)
Constant	83.41***	90.90***	80.93***	85.92***	100***	94.17***	99.68***	96.31***
	(5.964)	(8.092)	(22.13)	(5.622)	(–)	(2.229)	(0.283)	(1.678)
Observations	96	88	96	95	96	96	96	88
State Dummies							✓	
R^2	0.054	0.003	0.002	0.035	0.220	0.124	0.200	0.001

This table presents the results of a set of univariate regressions of the share of the plant's installed capacity under a long-term contract (%) on plant characteristics in FY 2015. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$

Table 8
Log capacity utilization (%) on log predicted coal price (INR/MMBtu), balanced panel, annual data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	0.321	0.331	0.292	0.295	−0.218	−0.152	−0.517	−0.217
	(0.504)	(0.542)	(0.558)	(0.478)	(0.415)	(0.433)	(0.528)	(0.411)
Log Heat Rate (MMBtu/MWh)				−0.244				−0.114
				(0.234)				(0.207)
Constant	2.499	2.447	2.597	3.242	5.215**	4.890**	6.709**	5.500***
	(2.507)	(2.698)	(2.798)	(2.397)	(2.061)	(2.152)	(2.658)	(1.912)
Observations	659	659	334	659	659	659	334	659
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.822	0.831	0.916	0.824	0.853	0.858	0.937	0.853
SE Clusters (Plant)	87	87	72	87	87	87	72	87

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

ash content (~34 percent) and low gross calorific value (4,000 kcal/kg or 15.86 MMBtu/tonne on average) compared to imported coal.[10]

In order to examine the contributions of within-plant changes and output reallocation across plants to the overall decline in heat rates over time, I decompose month-to-month changes in generation-weighted heat rates into the sum of three terms:

$$\Delta e_{t,t'} = \underbrace{\sum_i w_{it} \Delta e_{i;t,t'}}_{\text{Within-plant change}} + \underbrace{\sum_i \Delta w_{i;t,t'} e_{it}}_{\text{Reallocation across plants}} + \underbrace{\sum_i \Delta w_{i;t,t'} \Delta e_{i;t,t'}}_{\text{Correlation}}$$

The first term on the right-hand side is the inner product of the market share in period t and the change in heat rates between the two periods (i.e., the sum of the product of initial heat rate and the heat rate change); the second term is the inner product of the change in the market share and the initial heat rate; and the third term is the inner product or correlation of the change in market share and the change in heat rate. For nearly all plants and time periods, the third term turns out to be close to zero. The first term represents the change in heat rates accounted for by within-plant changes, holding fixed market shares at their initial levels. The second term is the contribution of changes in market shares to the overall change in heat rates, holding fixed heat rates at its initial level. The larger the first term is compared with the second, the more within plant changes explain the overall change in thermal efficiency.

Fig. 8(a) plots a running sum of the overall generation-weighted change in heat rates, within-plant changes and reallocation across plants from 2012 until 2020 for the plants in the balanced panel. We see that the efficiency improvement over the last decade was driven almost entirely by within-plant changes. The number of operational coal plants increased from 115 in the first month of the dataset (April 2012) to

[10] The two largest exporters of non-coking coal to India are Indonesia and Australia. Indonesian coal has an ash content between 5 and 12 percent, while Australian coal has an ash content between 8 and 20 percent (Sehgal and Tongia, 2016).

Table 9
Log capacity utilization (%) on log predicted coal price (INR/MMBtu) interacted with share of capacity contracted (%), balanced panel, annual data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	−2.700***	−2.716***	−4.183***	−2.819***	−2.957***	−3.193***	−4.624***	−3.056***
	(0.677)	(0.666)	(0.737)	(0.762)	(0.527)	(0.524)	(0.749)	(0.553)
Log $\hat{p}$ (INR/MMBtu) ×	0.0322***	0.0330***	0.0428***	0.0332***	0.0301***	0.0335***	0.0409***	0.0312***
Share of Capacity Contracted (%)	(0.00512)	(0.00528)	(0.00533)	(0.00650)	(0.00478)	(0.00521)	(0.00590)	(0.00541)
Log Heat Rate (MMBtu/MWh)				−0.325**				−0.220*
				(0.138)				(0.131)
Constant	1.998	1.684	4.147	2.973	4.379**	3.896**	7.402***	4.900***
	(2.271)	(2.410)	(2.594)	(2.160)	(1.849)	(1.853)	(2.473)	(1.746)
Observations	659	659	334	659	659	659	334	659
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.848	0.855	0.929	0.851	0.870	0.877	0.946	0.871
SE Clusters (Plant)	87	87	72	87	87	87	72	87

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 10
Log capacity utilization (%) on log predicted coal price (INR/MMBtu) interacted with categories of the share of capacity contracted, balanced panel, annual data.

	Dependent Variable: log Capacity Utilization (%)			
	Weighted by capacity			
	(1)	(2)	(3)	(4)
Log $\hat{p}$ (INR/MMBtu)	−2.975***	−2.812***	−1.896**	−0.980
	(0.776)	(0.404)	(0.746)	(0.756)
Log $\hat{p}$ (INR/MMBtu) × **1**[Share of Capacity Contracted > 0%]	2.751***			
	(0.582)			
Log $\hat{p}$ (INR/MMBtu) × **1**[Share of Capacity Contracted > 20%]		2.817***		
		(0.287)		
Log $\hat{p}$ (INR/MMBtu) × **1**[Share of Capacity Contracted > 80%]			1.851***	
			(0.670)	
Log $\hat{p}$ (INR/MMBtu) × **1**[Share of Capacity Contracted > 90%]				0.773
				(0.628)
Constant	5.295**	4.305**	4.602**	5.364***
	(2.091)	(1.824)	(1.903)	(2.010)
Observations	659	659	659	659
Plant FE	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓
R^2	0.857	0.872	0.867	0.858
SE Clusters (Plant)	87	87	87	87

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) fully interacted with dummies indicating whether the share of the plant's installed capacity allocated under long-term contract(s) is above various thresholds using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

174 in the last month of the dataset (March 2020), with only half a dozen plant retirements over the course of this period. Therefore, the greater reallocation across plants that is seen in the unbalanced panel in Fig. 8(b) can be attributed to the rising market shares of new entrants. While the within-plant improvements could be due to investments that improved the heat rate technology, these changes could also be the result of reallocation from less to more-efficient units within plants. Due to data limitations, I cannot observe heat rates at the unit level, and so I cannot separate these two channels.

The pattern indicating that the majority of efficiency gains over the study period stem from within-plant changes rather than reallocation across more efficient plants may reflect plant-level responses to cost pressures or regulatory drivers such as India's Perform, Achieve, and Trade (PAT) scheme, introduced by the Bureau of Energy Efficiency in 2012. PAT set mandatory energy-saving targets for large industrial consumers — including coal-based power stations — and allowed trading of energy-saving certificates, potentially incentivizing internal efficiency improvements even under inflexible dispatch

Table 11
Log capacity utilization (%) on log predicted coal price (INR/MMBtu), balanced panel, monthly Data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	0.366	0.363	0.0866	0.345	−0.237	−0.183	−0.686	−0.233
	(0.509)	(0.538)	(0.559)	(0.485)	(0.459)	(0.494)	(0.453)	(0.453)
Log Heat Rate (MMBtu/MWh)				−0.322**				−0.133
				(0.127)				(0.0990)
Constant	2.234	2.249	3.575	3.149	5.271**	5.006**	7.490***	5.587**
	(2.531)	(2.675)	(2.794)	(2.362)	(2.279)	(2.453)	(2.273)	(2.195)
Observations	7374	7374	5128	7374	7374	7374	5128	7374
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × YM FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.642	0.657	0.678	0.645	0.676	0.687	0.712	0.676
SE Clusters (Plant)	87	87	87	87	87	87	87	87

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) using monthly data. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 12
Log capacity utilization (%) on log predicted coal price (INR/MMBtu) interacted with the share of capacity contracted (%), balanced panel, monthly data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	−2.508***	−2.373**	−3.090**	−2.625**	−3.084***	−3.119***	−4.319***	−3.149***
	(0.901)	(0.989)	(1.394)	(0.998)	(0.750)	(0.840)	(1.182)	(0.780)
Log $\hat{p}$ (INR/MMBtu) ×	0.0306***	0.0295***	0.0318**	0.0316***	0.0305***	0.0315***	0.0373***	0.0313***
Share of Capacity Contracted (%)	(0.00773)	(0.00851)	(0.0128)	(0.00913)	(0.00691)	(0.00774)	(0.0117)	(0.00741)
Log Heat Rate (MMBtu/MWh)				−0.354***				−0.168**
				(0.105)				(0.0787)
Constant	1.786	1.646	4.032	2.775	4.748**	4.451*	7.599***	5.131**
	(2.479)	(2.550)	(2.794)	(2.342)	(2.144)	(2.262)	(2.200)	(2.084)
Observations	7374	7374	5128	7374	7374	7374	5128	7374
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × YM FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × YM FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.651	0.665	0.686	0.655	0.683	0.694	0.720	0.684
SE Clusters (Plant)	87	87	87	87	87	87	87	87

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using monthly data. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

regimes.[11] While the present study cannot separately identify the impact of PAT from other contemporaneous factors, its implementation likely contributed to observed within-plant gains in thermal efficiency.

In contrast, the limited role of between-plant reallocation highlights an institutional constraint in India's electricity sector: dispatch decisions are heavily shaped by long-term bilateral contracts, which secure cost recovery for fixed capital investments but weaken marginal incentives. Although centrally owned plants are often scheduled based on merit order dispatch, the ranking is typically determined by declared variable (marginal) cost, which itself depends on delivered coal prices. As a result, plants may still respond to coal price variation in their operating decisions, especially when a portion of their capacity is exposed to short-term markets or surplus capacity is bid into power exchanges. However, for plants under strict long-term contracts with bundled fixed and variable costs, responsiveness to coal prices is muted. This helps explain the heterogeneity in utilization elasticities observed in the empirical results.

Splitting the sample of coal plants in the balanced panel into quartiles of the distribution of heat rates in FY 2012 and FY 2013, the first two years of the data, we see that the improvement in generation-weighted heat rates and specific coal consumption is concentrated among plants that were in the fourth quartile of the heat rate distribution at baseline, or the ones that were the least efficient (Figs. 9 and 10). Furthermore, that improvement appears to coincide with a steep increase in capacity-weighted utilization rates and relatively stable unweighted utilization rates in the fourth quartile (Fig. 11),

[11] The Perform, Achieve and Trade (PAT) scheme was launched in 2012 by India's Bureau of Energy Efficiency under the National Mission on Enhanced Energy Efficiency (NMEEE). The first cycle (2012–2015) covered eight energy-intensive sectors — thermal power, iron and steel, cement, fertilizers, aluminum, pulp and paper, textiles, and chlor-alkali — and included over 400 Designated Consumers (DCs), accounting for nearly one-third of commercial energy use in India. Under PAT, each DC was assigned a specific energy reduction target, and those exceeding targets could trade Energy Saving Certificates (ESCerts) on power exchanges.

Table 13
Log capacity utilization (%) on log predicted coal price (INR/MMBtu), unbalanced panel, annual data.

Dependent Variable: log Capacity Utilization (%)								
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	0.0478	0.0647	−0.552	0.0762	−0.331	−0.315	−1.083	−0.308
	(0.411)	(0.417)	(0.607)	(0.404)	(0.352)	(0.352)	(0.748)	(0.356)
Log Heat Rate (MMBtu/MWh)				−0.277*				−0.177
				(0.141)				(0.134)
Constant	3.791*	3.706*	6.755**	4.346**	5.726***	5.645***	9.499**	6.052***
	(2.055)	(2.085)	(3.046)	(1.957)	(1.757)	(1.756)	(3.771)	(1.666)
Observations	895	895	454	895	895	895	454	895
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.829	0.835	0.911	0.832	0.843	0.846	0.921	0.844
SE Clusters (Plant)	137	137	106	137	137	137	106	137

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 14
Log capacity utilization (%) on log predicted coal price (INR/MMBtu) interacted with the share of capacity contracted (%), unbalanced panel, annual data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	−1.409*	−1.402	−3.276***	−1.396	−1.109	−1.327	−3.766***	−1.118
	(0.819)	(0.856)	(1.079)	(0.857)	(0.898)	(0.912)	(1.271)	(0.921)
Log $\hat{p}$ (INR/MMBtu)×	0.0167**	0.0166**	0.0305***	0.0169**	0.00933	0.0117	0.0294***	0.00975
Share of Capacity Contracted (%)	(0.00773)	(0.00802)	(0.00953)	(0.00815)	(0.00889)	(0.00911)	(0.0104)	(0.00908)
Log Heat Rate (MMBtu/MWh)				−0.286**				−0.194*
				(0.116)				(0.116)
Constant	3.323	3.311	6.210*	3.891**	5.281***	5.278***	9.230**	5.621***
	(2.024)	(2.041)	(3.216)	(1.964)	(1.732)	(1.702)	(3.953)	(1.677)
Observations	895	895	454	895	895	895	454	895
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.836	0.841	0.917	0.839	0.845	0.849	0.927	0.846
SE Clusters (Plant)	137	137	106	137	137	137	106	137

This table presents the results of regressions of the log of capacity utilization (%) on the log of the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

which implies that there was likely some reallocation of output within that group.

Table 2 summarizes the characteristics of coal plants in the balanced panel by quartiles of the distribution of heat rates at baseline. On average, power plants that are more efficient, i.e. in the lower quartiles of the heat rate distribution, are newer, more likely to be privately owned, use imported coal and are more likely to have installed more efficient supercritical boiler technology than power plants that are less efficient. Tables 3 and 4 report summary statistics of plant operations, efficiency and characteristics separately for plants in the balanced and unbalanced panels using monthly and annual data respectively. Capacity figures in the generation data exclude units that are down for extended periods due to long-term maintenance projects, renovations or shortages of fuel or water. If all units are not operational, the monitored capacity is reported as zero or missing, in which case the plant is dropped from the sample. Since there are more partially-contracted plants in the unbalanced panel and plants that have lesser capacity allocated under long-term PPAs find it difficult to acquire long-term fuel supply contracts, which implies they are more likely to be sitting idle, the mean monitored capacity of plants in the unbalanced panel is lower than in the balanced panel.

The limited reallocation of output across plants observed in Fig. 8(a) is consistent with the narrative that the impact of rising coal prices on power plant operations is mediated by bilateral contracts. As depicted in a series of correlation plots in Figs. 12(a)–12(c), while plants that have lower marginal cost (INR/MWh) are not more likely to have long-term contracts, contract status is positively correlated with the plant's utilization rate.[12]. In the figures, capacity utilization and heat rates are both residualized on a time trend, aggregated at the plant level, and weighted by their monitored capacity.

Figs. 13(a)–14(b) present histograms of the share of capacity contracted at the plant level. While 81 of the 191 coal plants in the dataset are either partially contracted or uncontracted, the capacity-weighted histograms indicate that the vast majority of installed capacity is fully

[12] A coal plant's marginal cost (INR/MWh) reflects both its thermal efficiency and the cost of transporting coal to the plant.

Table 15
Robustness: Is the effect of contract status driven by potential confounders?

Dependent Variable: log Capacity Utilization (%)				
	(1)	(2)	(3)	(4)
Log $\hat{p}$ (INR/MMBtu)	−2.236***	−2.398***	−2.387***	−2.293***
	(0.470)	(0.550)	(0.547)	(0.535)
Log $\hat{p}$ (INR/MMBtu) × Share of Capacity Contracted (%)	0.0252***	0.0256***	0.0269***	0.0256***
	(0.00470)	(0.00458)	(0.00468)	(0.00480)
Log $\hat{p}$ (INR/MMBtu) × Age of Oldest Unit	−0.000625	−0.00163	0.00144	0.00232
	(0.00873)	(0.00780)	(0.00743)	(0.00758)
Log $\hat{p}$ (INR/MMBtu) × Central Sector		0.363**	0.385*	0.369*
		(0.172)	(0.196)	(0.197)
Log $\hat{p}$ (INR/MMBtu) × Private Sector		−0.145	−0.0191	−0.00768
		(0.366)	(0.334)	(0.329)
Capacity (MW)			0.000419	0.000645
			(0.000480)	(0.000483)
Log $\hat{p}$ (INR/MMBtu) × Capacity			−0.0000552	−0.0000993
			(0.0000892)	(0.0000893)
Log $\hat{p}$ (INR/MMBtu) × CFBC Boiler				−1.670**
				(0.773)
Log $\hat{p}$ (INR/MMBtu) × Supercritical Boiler				0.528
				(0.391)
Constant	3.192*	3.297*	1.956	1.946
	(1.731)	(1.729)	(1.885)	(1.852)
Observations	659	659	659	659
Plant FE	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓
R^2	0.812	0.820	0.824	0.827
SE Clusters (Plant)	87	87	87	87

This table presents the results of regressions of log of capacity utilization (%) on the log of predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%), age of the oldest generating unit, ownership type (state government owned plants are the omitted category), capacity (MW), boiler type (pulverized coal is the omitted category) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 16
Panel tobit: Capacity utilization (%) on predicted coal price (INR/MMBtu), balanced panel, annual data.

Dependent Variable: Capacity Utilization (%)								
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
$\hat{p}$ (INR/MMBtu)	−0.283	−0.279*	−0.401*	−0.301*	−0.295**	−0.307**	−0.444**	−0.304**
	(0.178)	(0.151)	(0.224)	(0.172)	(0.137)	(0.122)	(0.212)	(0.140)
Heat Rate (MMBtu/MWh)				−0.439				−0.307
				(0.578)				(0.539)
Constant	166.5***	152.0***	132.0***	160.8***	159.5***	152.8***	130.2***	154.6***
	(31.04)	(27.40)	(33.04)	(25.92)	(27.00)	(24.04)	(30.64)	(23.99)
Observations	736	736	409	704	736	736	409	704
Regression	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit
Uncensored Observations	718	718	409	703	718	718	409	703
Left-Censored Observations	17	17	0	0	17	17	0	0
Right-Censored Observations	1	1	0	1	1	1	0	1
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
SE Clusters (Plant)	92	92	85	90	92	92	85	90

This table presents the results of Tobit regressions of capacity utilization (%) on the predicted coal price (INR/MMBtu) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

contracted. The balanced panel has substantially fewer partially contracted and uncontracted plants. Figs. 15(a)–16(b) present histograms of the share of coal imported at the plant level. 89 plants in the balanced panel and 139 plants in the unbalanced panel used at least some amount of imported coal. Finally, Figs. 17 and 18 illustrate the number of coal plants and the total coal-based capacity contracted to each state by ownership type.[13] Coal plants that are owned by one of the state governments are typically only contracted with the distribution utilities in the state that they are located in, while central government-owned plants and privately-owned plants are on average contracted with 6.5 and 1.3 states respectively.

3. Empirical strategy

To estimate the effect of coal prices on plant utilization rates, I use plant by time-level variation in the delivered price of domestic coal, holding fixed the average grade of coal the plant consumes and the

[13] A power plant is contracted with a state if it has a PPA with at least one of the distribution utilities in the state.

Table 17
Panel tobit: Capacity utilization (%) on predicted coal price (INR/MMBtu) interacted with the share of capacity contracted (%), balanced panel, annual data.

	Dependent Variable: Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
$\hat{p}$ (INR/MMBtu)	−1.126***	−1.030***	−1.666***	−1.231***	−1.144***	−1.131***	−1.775***	−1.160***
	(0.217)	(0.218)	(0.274)	(0.174)	(0.158)	(0.172)	(0.244)	(0.156)
$\hat{p}$ (INR/MMBtu) ×	0.00921***	0.00827***	0.0136***	0.0101***	0.00976***	0.00959***	0.0144***	0.00985***
Share of Capacity Contracted (%)	(0.00196)	(0.00209)	(0.00249)	(0.00152)	(0.00143)	(0.00171)	(0.00220)	(0.00136)
Heat Rate (MMBtu/MWh)				−0.295				−0.338
				(0.364)				(0.357)
Constant	151.4***	144.9***	120.3***	147.0***	136.1***	136.8***	116.0***	133.7***
	(20.21)	(21.14)	(27.14)	(18.68)	(16.35)	(18.67)	(26.23)	(17.44)
Observations	736	736	409	704	736	736	409	704
Regression	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit
Uncensored Observations	718	718	409	703	718	718	409	703
Left-Censored Observations	17	17	0	0	17	17	0	0
Right-Censored Observations	1	1	0	1	1	1	0	1
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
SE Clusters (Plant)	92	92	85	90	92	92	85	90

This table presents the results of Tobit regressions of capacity utilization (%) on the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 18
Panel tobit: Capacity utilization (%) on predicted coal price (INR/MMBtu), unbalanced panel, annual data.

	Dependent Variable: log Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
$\hat{p}$ (INR/MMBtu)	−0.103	−0.0806	−0.125	−0.210	−0.209*	−0.218*	−0.236	−0.273**
	(0.159)	(0.164)	(0.223)	(0.151)	(0.123)	(0.124)	(0.195)	(0.125)
Heat Rate (MMBtu/MWh)				−0.970***				−0.758**
				(0.372)				(0.379)
Constant	131.3***	128.7***	67.90	151.0***	139.5***	142.7***	87.41**	154.7***
	(25.29)	(25.70)	(45.57)	(22.29)	(21.60)	(21.63)	(39.92)	(20.95)
Observations	1188	1188	551	957	1188	1188	551	957
Regression	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit
Uncensored Observations	1040	1040	550	956	1040	1040	550	956
Left-Censored Observations	147	147	1	0	147	147	1	0
Right-Censored Observations	1	1	0	1	1	1	0	1
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
SE Clusters (Plant)	155	155	132	148	154	154	132	148

This table presents the results of Tobit regressions of capacity utilization (%) on the predicted coal price (INR/MMBtu) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

average distance that coal was transported before arriving at the plant at baseline levels:

$$u_{it} = \beta_p \hat{p}_{it} + \lambda_i + \gamma_s t + \gamma_b t + \gamma_c t + \epsilon_{it} \quad (1)$$

u_{it} is the utilization rate of plant i at time t, which is calculated as a share of the plant's monitored capacity, or the installed capacity that is not under long-term outage. The predicted price, $\hat{p}_{it}$, is constructed using the time-varying tax-inclusive notified coal price (INR per tonne), $price_{gt}$, for the grade corresponding to the weighted average gross calorific value of the coal that plant i received in FY 2015, $\mathbf{1}_{ig,2015}$. I divide the per-tonne price by the weighted average gross calorific value of coal that plant i received in FY 2015, $GCV_{i,2015}$, to convert the price from INR per tonne to INR per MMBtu. Similarly, I compute the transportation component of the predicted price using the average distance that coal is transported before arriving at the plant in FY 2015, $d_{i,2015}$ and the time-varying tax-inclusive notified freight price in INR per tonne for that distance range, $price_{dt}$, dividing the per-tonne freight price by the weighted average gross calorific value of the coal that the plant received in FY 2015 to convert the price from INR per tonne to INR per MMBtu.

$$\hat{p}_{it} = \mathbf{1}_{ig,2015} \times \frac{price_{gt}}{GCV_{i,2015}} + d_{i,2015} \times \frac{price_{dt}}{GCV_{i,2015}} \quad (2)$$

In order to estimate the price elasticity of gasoline demand in the U.S., Davis and Kilian (2011) use changes in taxes on gasoline consumption across states (excluding ad-valorem taxes) as an instrument for the price of gasoline. Since coal production is largely controlled by a single public sector enterprise in India with negligible cross-sectional variation in taxes, changes in taxes alone do not provide a sufficient source of variation in the delivered price of coal. I use FY 2015 as the

Table 19
Panel tobit: capacity utilization (%) on predicted coal price (INR/MMBtu) interacted with the share of capacity contracted (%), unbalanced panel, annual data.

	Dependent Variable: Capacity Utilization (%)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
$\hat{p}$ (INR/MMBtu)	−0.354*	−0.310	−0.972***	−0.669**	−0.305	−0.377	−1.104***	−0.533*
	(0.209)	(0.220)	(0.323)	(0.283)	(0.238)	(0.248)	(0.289)	(0.317)
$\hat{p}$ (INR/MMBtu) ×	0.00308	0.00267	0.00978***	0.00548**	0.00126	0.00196	0.00979***	0.00331
Share of Capacity Contracted (%)	(0.00188)	(0.00198)	(0.00255)	(0.00252)	(0.00225)	(0.00233)	(0.00246)	(0.00294)
Heat Rate (MMBtu/MWh)				−0.886***				−0.753**
				(0.311)				(0.337)
Constant	124.3***	123.9***	65.14*	139.1***	134.9***	136.8***	89.57**	143.4***
	(24.37)	(25.13)	(38.83)	(18.95)	(20.62)	(20.64)	(35.16)	(18.80)
Observations	1188	1188	551	957	1188	1188	551	957
Regression	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit	Tobit
Uncensored Observations	1040	1040	550	956	1040	1040	550	956
Left-Censored Observations	147	147	1	0	147	147	1	0
Right-Censored Observations	1	1	0	1	1	1	0	1
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
SE Clusters (Plant)	155	155	132	148	154	154	132	148

This table presents the results of Tobit regressions of capacity utilization (%) on the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

Table 20
Log heat rate (MMBtu/MWh) on log predicted coal price (INR/MMBtu), balanced panel, annual data.

	Dependent Variable: log Heat Rate (MMBtu/MWh)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	−0.0901	−0.0767	−0.0686	−0.103	−0.00127	−0.00347	0.258	0.00346
	(0.203)	(0.194)	(0.242)	(0.211)	(0.190)	(0.197)	(0.258)	(0.192)
Log Capacity Utilization (%)	−0.0403	−0.0302	−0.0247		−0.0217	−0.0204	0.0168	
	(0.0393)	(0.0380)	(0.0368)		(0.0395)	(0.0402)	(0.0352)	
Constant	3.146***	3.039***	2.976**	3.046***	2.621***	2.626***	1.146	2.507***
	(1.001)	(0.955)	(1.214)	(1.049)	(0.956)	(0.993)	(1.307)	(0.952)
Observations	659	659	334	659	659	659	334	659
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.859	0.867	0.949	0.858	0.863	0.867	0.948	0.863
SE Clusters (Plant)	87	87	72	87	87	87	72	87

This table presents the results of regressions of the log of heat rate (MMBtu/MWh) on the log of the predicted coal price (INR/MMBtu) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

base year instead of FY 2012 due to the dramatic decline in the average grade of coal dispatched to power plants in FY 2014, which occurred as a consequence of the Supreme Court's decision to revoke licenses for operating captive coal blocks. Since $\hat{p}$ holds fixed the grade of the coal that the plant consumes, choosing a year that is more representative of the entire eight-year sample in terms of the composition of coal grades delivered to power plants lends greater statistical power to the analysis.

In Eq. (1), λ_i represents plant fixed effects, $\gamma_s t$ are state-level trends, where s indicates the state that the plant is located in, and $\gamma_b t$ are boiler type-level trends, where b indicates the boiler type of the median generating unit of the plant. I also calculate deciles of the distribution of the operational capacity (MW) of coal plants and control for capacity decile-level trends, $\gamma_c t$. In order to difference out effects that are common to plants that are contracted with state p in time t, I tried including a vector of dummies for whether or not plant i has a long-term contract with state p, each interacted with a time trend, but these models leave fewer observations as smaller states that are contracted with a single coal plant are dropped out. While coal accounts for 70%–80% of annual electricity generation in India, run-of-the-river hydroelectric generation typically substitutes for coal-fired generation during the monsoon season which lasts from July to September (Fig. 19), contributing to a temporary reduction in the emissions intensity of the power sector during those months (Fig. 20). This substitution effect will likely be more concentrated in states with greater hydroelectric power availability. The state-level trend absorbs any regional variation in utilization rates that is driven by seasonal or weather differences. State and time fixed effects alone explain 95% of the variation in state-level electricity demand.

Since the identifying variation in the predicted price of coal comes from the composition of grades received by the plant and the distance coal is transported before arriving at the plant in FY 2015, I report the unconditional correlations of the weighted average gross calorific value of coal received and the weighted average distance coal is transported with plant characteristics in FY 2015 in Tables 5 and 6 respectively.

Table 21
Log capacity utilization (%) on log predicted coal price (INR/MMBtu) interacted with the share of capacity contracted (%), balanced panel, annual data.

	Dependent Variable: log Heat Rate (MMBtu/MWh)							
	Unweighted				Weighted by capacity			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log $\hat{p}$ (INR/MMBtu)	−0.537	−0.781	−0.916**	−0.368	−0.591	−0.829*	−0.447	−0.452
	(0.597)	(0.521)	(0.458)	(0.572)	(0.520)	(0.488)	(0.441)	(0.505)
Log $\hat{p}$ (INR/MMBtu) ×	0.00484	0.00776	0.00818**	0.00283	0.00642	0.00904*	0.00690*	0.00501
Share of Capacity Contracted (%)	(0.00592)	(0.00527)	(0.00394)	(0.00556)	(0.00552)	(0.00523)	(0.00379)	(0.00532)
Log Capacity Utilization (%)	−0.0625**	−0.0645**	−0.0531*		−0.0468	−0.0568**	−0.00941	
	(0.0272)	(0.0250)	(0.0313)		(0.0285)	(0.0276)	(0.0316)	
Constant	3.127***	2.943***	3.346***	3.002***	2.573***	2.536**	1.438	2.368**
	(1.003)	(0.950)	(1.197)	(1.065)	(0.951)	(1.002)	(1.306)	(0.968)
Observations	659	659	334	659	659	659	334	659
Plant FE	✓	✓	✓	✓	✓	✓	✓	✓
State × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Capacity Decile × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Boiler Type × Year FE	✓	✓	✓	✓	✓	✓	✓	✓
Ownership × Year FE		✓				✓		
No Imported Coal Received			✓				✓	
R^2	0.862	0.873	0.951	0.859	0.867	0.872	0.949	0.865
SE Clusters (Plant)	87	87	72	87	87	87	72	87

This table presents the results of regressions of the log of heat rate (MMBtu/MWh) on the log of the predicted coal price (INR/MMBtu) fully interacted with the share of the plant's installed capacity under long-term contract(s) (%) using data aggregated to the annual level. Standard errors are clustered at the plant level. The sample is restricted to plants in the balanced panel that do not exclusively use imported coal. * $p < .1$, ** $p < .05$, *** $p < .01$.

The weighted average gross calorific value appears to be uncorrelated with size, age, the share of capacity contracted, ownership type and the share of coal imported. Plants that use lower grade coal will mechanically consume more coal to generate a MWh of electricity, which explains the negative coefficient in column (2). State dummies explain 36.5% of the variation in the weighted average gross calorific value, reflecting the spatial heterogeneity in the grade of coal available for electricity generation. Plants that are located further away from coal mines are significantly more efficient in terms of the amount of coal they consume per MWh of electricity generated. These plants are also more likely to be owned by the central government and are more likely to have installed a highly-efficient Circulating Fluidized Bed Combustion (CFBC) boiler.

The lack of reliable data on the grade of imported coal shipped to power plants and on the prices paid for imported coal and non-rail-based freight transportation generates measurement error in the predicted coal price. To address potential bias introduced by measurement error, I exclude the 14 coal plants that exclusively use imported coal from the analysis and I restrict the sample to observations where plant i received coal by rail in time t, leaving 96 plants in the balanced panel and 169 plants in the unbalanced panel. Furthermore, I estimate models that restrict the sample to plants that received no imported coal in time t. I also estimate all models weighting observations by capacity given that monthly coal prices are much less variable at larger plants. In their econometric model of heat rates of coal plants in the U.S., Linn et al. (2014) also aggregate observations to 5-year time periods to reduce measurement error. Since I do not have access to as long a time series, I am only able to aggregate observations to the annual level. Estimating Eq. (1) using annual-level data is also more appropriate for the Indian context as notified domestic coal prices typically do not change on a month-to-month basis (Fig. 4). Longer-run estimates are more likely to pick up any rebound effect in utilization resulting from decisions that influence the thermal efficiency of plants in response to a change in coal prices, for example, changes in how plant operators control boiler conditions, and, occasionally, installation of new technology or larger maintenance projects. Consequently, longer-run estimates of the elasticity of utilization rates with respect to coal prices are more relevant for evaluating the persistent impact of policies that make fossil fuel generation more expensive, such as carbon pricing.

To study how a plant's contract status affects its utilization response to coal prices, I fully interact the share of the plant's capacity that has been allocated under long-term contract(s), $contract_i$, with the predicted price of coal at time t:

$$u_{it} = \beta_p \hat{p}_{it} \times contract_i + \lambda_i + \gamma_s t + \gamma_b t + \gamma_c t + \epsilon_{it} \tag{3}$$

The sign of the coefficient on the interaction term indicates whether a higher share of capacity contracted augments (negative) or dampens (positive) the elasticity of plant utilization with respect to coal prices. As described in Section 1.1, the contract status of power plants is determined in large part by the evolution of the regulatory frameworks that governed the power sector. The power sector liberalization reforms of the early 2000s led to greater entry of private power producers. While these newer plants were more efficient than the older state-owned plants, many struggled to obtain PPAs. In contrast, plants built by central government-owned power generation companies, such as NTPC, were effectively guaranteed PPAs during this period. This phenomenon is reflected in Table 7, which shows how contract status is correlated with plant characteristics. Compared to state-owned plants, privately-owned power plants have a significantly lower share of their capacity allocated under long-term contracts. For these reasons, the contract status of power plants in Eq. (3) is likely to be endogenous. I include interactions of plant characteristics and the predicted coal price to examine whether the coefficient on the interaction of the plant's share of capacity contracted and the predicted price is driven by these potential confounders.

Since the econometric analysis reflects a static model of the electricity sector and plant entry or exit decisions could be correlated with unobserved plant characteristics, models that restrict the estimation sample to include only the power plants that are present in the balanced panel are preferred. However, newer plants that enter during this period are likely to be more efficient and less contracted. To address selection concerns, I estimate the model using all plants in the unbalanced panel as well. Since newer plants are also more likely to burn higher-grade imported coal or to blend domestic and imported coal, excluding observations where plants receive imported coal becomes more important in the unbalanced panel given the likelihood of greater measurement error. Finally, I estimate elasticities of utilization with respect to coal prices conditional on the plant owners' decision to operate their plants. Since the owners of plants that lack contracts are more likely to leave their plants idle, these estimates do not take into account the extensive margin of the utilization response and can therefore be considered a lower bound of the overall effect of contract status. Power plants that were under long-term outage during the sample period comprise about 10% of the observations. Not only are plant capacities and utilization rates unobserved in these instances, but often the variables needed to compute the predicted price, such as the grade composition of coal consumed by the plant and the average distance that coal was transported in FY 2015, are also missing. While there are fewer cases where an operational coal plant with an observable predicted price was not run even once over the course of a year, I also estimate Equation (1) and (3) using a Tobit panel selection model since the dependent variable, the utilization rate, is censored from below at 0.

Once coal plants declare their availability on a day-ahead basis, the extent to which they are utilized is largely determined by the State Load Dispatch Centres that are responsible for scheduling and dispatching power plants to meet their states' demand, while also ensuring that the frequency on their grid is balanced. On the other hand, the long-run efficiency of power plants is directly impacted by the decisions of plant owners. To examine whether the thermal efficiency of power plants that are more contracted is also less sensitive to changes in coal prices, conditional on utilization, I estimate the following model of heat rates:

$$e_{it} = \beta_p \hat{p}_{it} \times contract_i + \beta_u u_{it} + \lambda_i + \gamma_s t + \gamma_b t + \gamma_c t + \epsilon_{it} \tag{4}$$

e represents the thermal efficiency of power plant i as measured by its heat rate at time t. While heat rates implicitly capture any changes in the grade of coal consumed by the plant, plant owners have limited ability to alter the grade of coal they burn for two reasons. First, the plant's heat rate technology is generally only compatible with a specific range of coal grades. For example, supercritical boilers require higher grade coal compared to the more common subcritical boilers that use lower-grade pulverized coal. Second, Coal India typically supplies the grade of coal that is most readily available at any given time, even if it happens to be lower than the grade specified in the fuel supply contract with the power plant. In fact, the declared quality of coal supplied by Coal India is often inferior to the actual grade determined after sampling analysis, a phenomenon referred to as slippage (ETEnergyWorld, 2021). Therefore, changes in heat rates are more likely to occur as a result of the decisions of plant owners involving maintenance, boiler operation and installation of new technology. Some of these changes, however, take place over multiple years and will not be captured in the simultaneous estimates.

Since plants owned by the central government, the state governments and the private sector may have different incentives to improve heat rates, I estimate Eq. (4) controlling for ownership-level trends. While I also observe the parent company that owns the power plant, I do not control for firm-level trends as many private power producers may only operate a single power plant in time t, so a large number of plants will be dropped from the sample. Nevertheless, the concern that certain power producers may be able to negotiate favorable rates for coal is implausible in this context as more than 80% of domestic coal is produced by a single public-sector coal mining company and is procured through long-term fuel supply contracts at regulated prices.

4. Results

This section reports the estimated effects of coal prices on output and thermal efficiency. I discuss the magnitudes and robustness of the estimates as well as interactions with the plant's contract status. I then discuss what these estimates imply for the change in plant utilization that would be induced by a hypothetical carbon price, assuming that the tax is fully passed through to delivered coal prices.

Table 8 reports estimates of Eq. (1), where the dependent variable is the plant's utilization rate aggregated to the annual level. The main coefficient of interest is β_p, which is interpreted as the elasticity of utilization rates with respect to coal prices. Columns (1)–(4) present unweighted estimates, while columns (5)–(8) are weighted by the plants' monitored capacities. All specifications include state-level trends, capacity decile-level trends and boiler type-level trends. Columns (2) and (6) include ownership-level trends that difference out factors affecting utilization rates that are common to plants operated by the state governments, the central government or the private sector in time t. Columns (3) and (7) restrict the sample to observations where plants do not receive any imported coal. Columns (4) and (8) condition on the log of heat rates. Standard errors are clustered at the plant level. Across each of these specifications, the estimates are statistically insignificant at the 10% level. These results are consistent with short-run estimates reported in Table 11, which are larger in magnitude but still insignificant.

Table 9 reports estimates of Eq. (3) using data aggregated to the annual level. The coefficient in the first row represents the elasticity of utilization rates with respect to coal prices when the share of capacity contracted is 0%. The estimated elasticity for uncontracted plants is −2.957 in column (5), which implies that a 10% increase in coal prices reduces utilization rates by 29.6%. The point estimate is significant at the 1% level. To help put these magnitudes in context, the mean of the predicted delivered price of coal among uncontracted plants in the balanced panel is INR 110.04 per MMBtu (USD 1.51 per MMBtu) and the standard deviation is INR 17.83 per MMBtu (USD 0.24 per MMBtu). The mean utilization rate among these plants is 40.16% and the standard deviation is 19.79%. An INR 11 per MMBtu (USD 0.15 per MMBtu) increase in coal prices would correspond to a massive 11.24pp reduction in utilization rates among uncontracted plants. At the 5th percentile, the share of capacity contracted in the balanced panel increases to 88.71%, at which point the estimated elasticity declines in magnitude to −0.288 and is statistically insignificant at the 10% level. At higher shares of capacity contracted, an equivalent percent change in coal prices has no effect on utilization rates. Fig. 21(a) illustrates the point estimates and 95% confidence intervals of the average marginal effects over the distribution of the share of capacity contracted in the balanced panel. Table 12 reports estimates of the short-run utilization response to coal prices using monthly data. Among uncontracted plants, a 10% increase in coal prices reduces utilization by 30.8%. The point estimate is significant at the 1% level. At the 5th percentile of the distribution of the share of capacity contracted, the estimated elasticity declines to −0.376 and is statistically insignificant at the 1% level. Larger magnitudes of the price elasticities in the short run indicate that plant owners may be unable to adjust heat rates in response to price shocks on a month-to-month basis, which would imply a smaller rebound effect in utilization rates. Taken together, these results suggest that the utilization response to coal prices is concentrated among uncontracted plants. To investigate further, I define the share of capacity allocated under long-term contract(s) as a categorical variable, using thresholds of 0%, 20%, 80% and 90%, and repeat the analysis by interacting each indicator with the predicted price. As shown in Table 10, the elasticities are largest for power plants that are uncontracted. The magnitudes decline as the threshold increases, but there remains a significant effect of coal prices on utilization rates for plants that are at most 80% contracted, after which the effect dissipates.

As illustrated in the histograms in Figs. 13(a) and 14(a), there are more uncontracted and partially contracted plants in the unbalanced panel. Table 13 reports annual estimates of the elasticity of utilization with respect to domestic coal prices for all plants in the unbalanced panel. Table 14 reports estimates from the fully interacted model. Except for the models in columns (3) and (7), which restrict the sample to observations where plants do not receive any imported coal in time t, the point estimates of the coefficient on the log of the predicted price and the interaction term are statistically insignificant at the 10% level across all specifications. The estimated coefficient in column (7) suggests that among uncontracted plants, the estimated elasticity of utilization with respect to coal prices is −3.77 and is significant at the 1% level, implying that a 10% increase in coal prices would lead to a 37.7% or 15.14pp reduction in utilization rates. At the 5th percentile, the share of capacity contracted in the unbalanced panel increases to 42.3%, at which point the estimated elasticity reduces to −2.52 and remains significant at the 1% level. At higher shares of capacity contracted, an equivalent percent change in the coal price has no effect on utilization rates. Fig. 22(a) illustrates the point estimates and 95% confidence intervals of the average marginal effects over the distribution of the share of capacity contracted in the unbalanced panel. Imported coal comprises a larger share of overall coal consumption among newer plants as seen in Figs. 15(a) and 16(a). Therefore, Table 14 indicates, albeit suggestively, that plants that import a larger share of the coal they consume are less sensitive to changes in domestic coal prices.

Since Table 7 shows that the share of capacity contracted is correlated with plant characteristics, it is important to verify that the marginal effect of contract status on price sensitivity is not driven by these confounders. Table 15 reports annual estimates of Eq. (3) and each column adds interactions between the log of the predicted price and the following plant characteristics: age of the oldest generating unit; monitored capacity; dummies for ownership, where state-government owned plants are in the omitted category; and the boiler type of the median generating unit, where subcritical pulverized coal boilers are in the omitted category. All regressions include plant fixed effects and state-level trends and standard errors are clustered at the plant level. The estimated coefficient on the interaction between the predicted price and the share of capacity contracted remains stable in magnitude and significance across all specifications, which implies that the marginal effect of contract status is robust. Central government-owned coal plants appear to have a higher sensitivity of plant utilization to coal prices compared to state government-owned coal plants, which is not unexpected since central government plants sell to more states and are effectively competing in more markets.

Table 20 reports estimates of the elasticity of heat rates with respect to coal prices using data aggregated at the annual level. I include all the same controls as in the utilization rate estimation, and also control for the log of the utilization rate. Columns (1)–(4) report the unweighted estimates, while columns (5)–(6) weight the estimates by the plants' monitored capacities. Columns (4) and (8) do not condition on the log of capacity utilization. In general, the data reveals a weak relationship between coal prices and heat rates, suggesting that firms are not minimizing costs perfectly, which is not uncommon in industries that are heavily regulated. Table 21 reports the estimates of Eq. (4), fully interacting the log of the predicted price with the share of capacity contracted. To control for the potential correlation between entry and exit decisions and unobserved plant characteristics, the sample is restricted to the balanced panel of coal plants. Columns (3) and (7) further restrict the sample to observations where plants do not receive any imported coal in time t. Except for columns (3) and (7), the point estimates of the coefficient on the log of the predicted price and the interaction term are statistically insignificant at the 10% level across all specifications. The estimated coefficient in column (3) suggests that the elasticity of heat rates with respect to coal prices is −0.916 among uncontracted plants, which implies that a 10% increase in coal prices would reduce heat rates by 9.2% among this group. The point estimate is significant at the 5% level. At higher shares of capacity contracted, coal prices no longer have an effect on heat rates.

A secondary identification challenge in estimating the intensive-margin impacts of coal prices on utilization rates is that utilization rates are unobserved in cases where coal plants do not operate even once over the course of a year. Tables 16 reports estimates from Tobit regressions where the dependent variable is censored from below at 0. Table 17 reports estimates of models where the predicted price is fully interacted with the share of the plant's capacity allocated to state(s) under long-term contract(s). Tables 18 and 19 report results from estimating the same models with all plants in the unbalanced panel. The Tobit estimates support the two central findings of this paper: (a) on average, changes in coal prices have no effect on utilization rates, and (b) the demand for electricity from coal plants that have a higher share of their capacity allocated under long-term contracts is less sensitive to changes in coal prices. The coefficients on the predicted price in column (5) of Table 17 and column (7) of Table 19 are both significant at the 1% level and correspond to estimated elasticities of −2.94 and −3.14 for uncontracted plants, respectively. Since Tobit regressions typically have a higher intercept and a flatter slope compared to OLS with censored data, these elasticities are slightly smaller than the elasticities estimated in column (5) of Table 9 and in column (7) of Table 14. These estimates do not, however, fully resolve the sample selection induced by uncontracted plants that remained idle throughout the sample period, and should therefore be seen as a lower bound of the impact of contract status on coal price sensitivity.

Since heat rates are largely insensitive to changes in coal prices, a carbon price that makes coal-fired generation more expensive is unlikely to produce a large rebound effect. In other words, the policy is unlikely to affect plant utilization through an effect on heat rates. I use the estimated coefficients corresponding to the specification in column (5) of Table 9 to calculate the reduction in emissions from a USD 5 per tonne CO_2 (INR 362.42 per tonne CO_2) emissions tax, with the caveat that the elasticity only captures the intensive margin of the utilization response. The model allows heat rates to vary endogenously in response to a change in coal prices. For the calculations, I assume an average emissions factor of 0.09559 tonnes CO_2 per MMBtu of coal and a weighted average emissions rate of 1.04 tonnes CO_2 per MWh (Central Electricity Authority, 2018). The tax would translate to an average increase of INR 34.64 per MMBtu (USD 0.48 per MMBtu) in the delivered price of coal. Coal prices have no effect on utilization rates for plants that are more than 70% contracted and there are no plants whose share of capacity under long-term contract(s) is between 20% and 70% in the preferred balanced panel sample used in Table 9. In fact, there is only one plant that is 0% contracted and one that is 20% contracted, with capacities of 540 and 1,000 MW, respectively. The mean delivered coal price is INR 110.04 per MMBtu (USD 1.50 per MMBtu) for the 0% contracted plant and INR 147.47 per MMBtu (USD 2.01 per MMBtu) for the 20% contracted plant, implying that the tax would raise coal prices by 31.48% and 23.49%, respectively. The mean utilization rates of these plants are 40.16% and 62.93%. The estimated marginal effects (−2.96 at 0% contracted and −2.36 at 20% contracted) suggest that the tax would reduce utilization rates by 37.42pp and 34.89pp at each plant. These changes would imply an annual reduction in generation of 1,770,167 MWh and 3,056,025 MWh, respectively, assuming that each plant were operating at full capacity throughout the year, and the cumulative reduction in emissions would be approximately 5,019,240 tonnes CO_2 per year.

While it may seem appealing to estimate the emissions reductions under the assumption that all power plants would exhibit the same elasticity as that of the uncontracted plants if electricity were transacted through a centralized and dynamic market-based economic dispatch mechanism, that would not be an appropriate counterfactual as the elasticities under that scenario are likely to be significantly smaller, particularly for inframarginal plants. Furthermore, since the reduced-form analysis only captures partial equilibrium responses to price shocks, the elasticities of uncontracted plants may be higher precisely because the rest of the coal fleet is by and large fully contracted.

Nonetheless, the reduced form estimates indicate that an increase in prices will only reduce utilization and emissions among uncontracted coal plants and will not elicit any response from coal plants with higher levels of capacity allocated under long-term contracts. Future research can use the reduced form estimates from this study to calibrate models of the Indian electricity sector to generate precise estimates of the emissions reductions under a CO_2 emissions tax compared to policies that are more common in practice, such as uniform emissions rate standards, tradable performance standards and state-level renewable purchase obligations. Uniform emissions rate standards were recently applied for NO_X, SO_X, mercury and $PM_{2.5}$ emissions at thermal power plants in India and various states have implemented renewable purchase obligations, although the penalties for non-compliance in both cases remain unclear (Seligsohn and Tongia, 2017). The analysis presented here makes clear that market-based policies that aim to reduce CO_2 emissions in the Indian power sector will be less cost-effective under the current market design than in a more competitive market where plants are dispatched on the basis of their short-run marginal cost.

5. Policy implications

The empirical findings presented in this paper suggest that India's current electricity market structure — dominated by long-term power purchase agreements (PPAs) and cost-plus tariff mechanisms — limits the responsiveness of coal-fired power plants to changes in input prices. This institutional rigidity weakens the effectiveness of market-based environmental policies, such as carbon pricing, which rely on marginal incentives to shift dispatch patterns, improve fuel efficiency, or induce a reallocation of generation toward cleaner sources. These results underscore the need for complementary reforms in market design if India is to fully realize the environmental benefits of carbon pricing and other economic instruments.

One clear implication is the importance of accelerating the shift toward market-based economic dispatch (MBED). Under the current regime, most power is dispatched based on pre-scheduled bilateral contracts, insulating generators from real-time cost signals. MBED, which aims to centralize dispatch at the national level based on marginal cost and technical constraints, could improve system-wide efficiency and allow carbon prices to influence operational decisions. Pilots of MBED launched by the Ministry of Power and the Central Electricity Authority have already shown promise in improving utilization of lower-cost plants (Ministry of Power, 2021). Scaling up MBED would amplify the pass-through of coal and carbon price signals, especially for state and central government-owned plants with surplus or underutilized capacity.

Second, the findings point to the need for reforming the structure of PPAs to allow greater flexibility in dispatch and renegotiation. This could involve phasing out rigid "must-run" clauses and incorporating performance-based incentives that reward operational efficiency and emissions intensity. New procurement should prioritize short- and medium-term contracts via competitive power exchanges, allowing greater scope for dynamic market participation.

Finally, aligning regulatory incentives across jurisdictions will be essential. As the results show, generators exposed to short-term markets demonstrate significantly higher responsiveness to coal prices. This implies that harmonizing dispatch protocols, standardizing tariff structures, and encouraging open access across state boundaries could enhance the allocative efficiency of generation in response to both economic and environmental signals.

In sum, while carbon pricing can be a powerful tool for reducing emissions in the electricity sector, its effectiveness depends critically on the degree to which market institutions transmit price signals to operational behavior. India's electricity market reforms — particularly MBED and PPA restructuring — are therefore not just economic efficiency initiatives, but foundational to the success of the country's broader climate strategy.

6. Conclusion

Transacting electricity through systems of bilateral contracts substantially dampens the responsiveness of coal plant utilization to changes in coal prices, which implies that a price on carbon emissions will have lesser overall environmental benefit under such market conditions. Since long-term contracts limit reallocation of output across plants, power producers respond to price shocks primarily through within-plant changes. As a consequence, under the existing design of the Indian power sector, market-based policies have the potential to exacerbate underlying misallocation by pricing out newer and more efficient power plants that may lack contracts. Introducing dynamic market-based economic dispatch and greater regional integration of markets will not only reduce costs by facilitating more competition, but these changes could also unlock greater environmental benefits, both directly through the allocative efficiency improvement and indirectly through a market-based policy mechanism. However, states would have to surrender authorities granted to them by the Constitution of India to move to a centralized dispatch mechanism. Given these political economy considerations, large-scale market restructuring may not fully precede attempts by policymakers to reduce emissions in the electric power sector, which continues to rely heavily on coal. Therefore, understanding the cost-effectiveness of alternative policies under the existing market design is imperative.

In future work, I also plan to examine how the characteristics of the states that the plants are contracted with affects the elasticities of utilization and heat rates with respect to coal prices. For example, states that procure coal through a combination of long-term and short-term contracts as well as power exchanges may be able to reallocate output more efficiently as compared to states that procure power primarily via long-term contracts. Comparing the potential emissions reductions induced by market-based policies across states may also draw attention to the need for greater competition and regional integration in the electric power sector as well as in other emissions-intensive commodity-based industries.

CRediT authorship contribution statement

Shefali Khanna: Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

In this section, I use two hypothetical numerical examples to illustrate the mechanisms for output reallocation within a state's merit-order stack in response to a flat tax (INR × per tonne) on coal:

Mechanism 1: State j has power purchase contracts with two coal-fired power plants, A and B. The total variable cost (excluding labor and O&M) of each power plant is decomposed as follows:

	Plant A	Plant B
Coal cost (INR/MWh)	1,000	2,000
Freight cost (INR/MWh)	2,000	950
Total cost (INR/MWh)	3,000	2,950

Once the tax on coal is imposed, A's fuel cost rises by INR 200 and B's rises by INR 400, which flips the merit order in favor of the more efficient plant:

	Plant A	Plant B
Coal cost (INR/MWh)	1,200	2,400
Freight cost (INR/MWh)	2,000	950
Total cost (INR/MWh)	3,200	3,350

Mechanism 2: State j has power purchase contracts with two coal-fired power plants, C and D, which are both located at the mine-mouth and thus do not bear any freight cost. The fuel cost of each power plant is decomposed as follows:

	Plant C	Plant D
Heat rate (MMBtu/MWh)	8	10
Heat value (MMBtu/ton)	15	25
Coal price (INR/ton)	600	900
Fuel cost (INR/MWh)	320	360

If an INR 350 per ton tax on coal is imposed, the merit order flips in favor of the plant that consumes higher grade coal:

	Plant C	Plant D
Heat rate (MMBtu/MWh)	8	10
Heat value (MMBtu/ton)	15	25
Coal price (INR/ton)	950	1250
Fuel cost (INR/MWh)	506.67	500

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