The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market *

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Abstract

India's dysfunctional electricity sector is widely viewed as a constraint on growth and social welfare. In 2003, the Indian government instituted market-oriented reforms that opened access to the power grid and established exchanges for power trade. I use confidential data on hourly bids and offers to study the competitiveness of the resulting wholesale power market, in which tight constraints on transmission may limit competition across regions of the country. I estimate firm marginal costs from supply offers using first-order conditions for optimal bidding that account for the likelihood that transmission constraints will cut off demand and competing supply from other regions. Using these cost estimates, I run counterfactual simulations to measure the surplus gains from increasing transmission capacity. I find that relaxing import constraints into the two most constrained regions would increase total market surplus by 19 percent or USD 110 million per year. The strategic response of suppliers to transmission expansions accounts for 72 percent of this gain, indicating that new transmission greatly undercuts local market power. The marginal benefits of capacity expansion into the two most constrained regions exceed the marginal costs of investment by factors of 1.63 and 3.50, respectively. Liberalization in electricity generation requires that the government take a strong complementary role through regulation and infrastructure investment to ensure competition.

JEL Codes: 025, L11, L13, L94

1 Introduction

In the 1990s, India undertook a wave of economic reforms that lifted tariffs and swept away industrial licensing, a complex system of permits that specified what and how much manufacturers could produce. These reforms are widely credited with unleashing or at least aiding a period of high economic growth (Ahluwalia, 2002; Rodrik and Subramanian, 2005; Aghion

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et al., 2008; Bollard et al., 2013). One of the few industrial sectors untouched by this wave was electricity, a traditionally regulated industry with natural monopoly segments, which is now viewed as a primary constraint on growth (Economist, 2012). Roughly 300 million Indian citizens, one-quarter of the population, are not connected to the electric grid (International Energy Agency, 2011). Electric generating capacity has grown steadily, but not kept pace with demand, so that for those on the grid supply is on average 10 percent short of demand (Central Electricity Authority, 2011a). This figure does not include demand suppressed by the lack of power or the cost of compensatory investments, such as in captive generation capacity. Wolak (2008) wrote that it was "difficult to imagine more adverse initial conditions" for any electricity restructuring than were present in India. Nonetheless, the Indian government has instituted market-oriented reforms that aim to increase the supply of power through private investment and trade in the electricity sector. In particular, the Electricity Act of 2003 delicensed power generation, allowed open access to the power grid and established power exchanges to encourage wholesale trade (Thakur et al., 2005).

The competitiveness of this wholesale power market, because electricity cannot economically be traded by road or rail, depends on the constraints set by the electricity transmission grid. Legacy transmission networks in many countries, built when generators were regulated so that market power was not a concern, have often not had enough capacity to ensure wide competition when markets are deregulated (Borenstein et al., 2000; Wu et al., 2006; Joskow, 2008). The transmission grid in India, once opened, has likewise been inadequate to support a competitive national market.

I study the day-ahead electricity market as a window to the effects of congestion in the whole power system. The day-ahead market comprises a small share of volume but is an important platform for trade, because it is the residual claimant on the transmission capacity of the grid, receiving whatever capacity is left over after participants in earlier contract markets book their own corridor. This last position in transmission priority means that the day-ahead market bears a large share of the cost from transmission constraints, and that the power system as a whole is congested if and only if the day-ahead market is congested. The day-ahead market is also the only platform where electricity prices explicitly reflect transmission constraints, which makes the value of transmission on this platform clear. In the day-ahead market, there is congestion—meaning that some area is physically constrained from importing more from the rest of the market—46% of the time during my study period. When congestion arises, prices across regions diverge, and suppliers may have the opportunity to raise prices in the thinner, regional markets that are broken off by transmission constraints.

This paper estimates the potential welfare gains from investment in transmission infrastructure in the Indian electricity market. I use confidential data on hourly bids and offers from the leading power exchange in India, for the first analysis of the Indian wholesale market and arguably the first micro-econometric study of a wholesale power market in a developing country.[1] This first analysis is notable because the Indian market has some features, such as elastic demand from industrial consumers and even distribution companies, that sharply differ from the norm in liberalized power markets in developed countries. The data, vitally, include not only bids but also the region of the grid in which the bid was submitted and the hourly constraints on transmission capacity across regions, so that my analysis can account for the transmission constraints that bound, or might have bound, when the bidding took place.

The empirical approach is to value the loss of surplus from these constraints by estimating a structural model of bidding with transmission constraints and then simulating what market outcomes would have been if the grid had more capacity. For estimation, I calculate first-order conditions for profit-maximizing bids based on the residual demand curves faced by each seller and use these conditions as moments to back out the marginal costs of electricity supply. Because transmission congestion truncates power flows and thus competition across regions, the moment conditions for each seller reflect the residual demand they face within their own, possibly constrained region of the grid. For counterfactual outcomes, I restrict strategic sellers to Cournot strategies and estimate market outcomes under counterfactual levels of transmission constraints. I run these counterfactuals in two ways to separate whether transmission expansion benefits the market mainly through increases in trade, across regions with different prices, or by the mitigation of market power. In the first counterfactual scenario strategic bidders hold their bids fixed at their baseline level, so that the exercise of market power is held constant but the market can benefit from trade across regions with different electricity prices. In the second, strategic bids are endogenous and respond to the changes in

[1] Bacon and Besant-Jones (2001) describes the experimentation of developing and transition countries with different stages of electricity liberalization. Williams and Ghanadan (2006) and Jamasb (2005) survey the experience of such countries with reform. A number of studies, such as Zhang et al. (2008), estimate cross-country regressions to evaluate electricity reform in a structure-conduct-performance paradigm.

residual demand caused by increases in transmission capacity. For example, sellers in regions that are heavily import constrained may face more competition from imports and thus more elastic residual demand when transmission capacity increases.

The main finding of the paper is that the welfare gains from transmission expansion are large and mostly due to the competitive effects of additional transmission capacity. Counterfactual 1200 MW increases in import capacity to the North and South regions produce estimated welfare gains of INR 1.39 billion (USD 27.80 million) and INR 4.08 billion (USD 81.67 million) per annum, respectively, which together are 19% of the total baseline market surplus. By comparison with counterfactuals that hold strategic bids fixed at baseline levels, I calculate that 72% of this welfare gain is due to transmission expansion decreasing market power. That is to say, the primary cost of transmission constraints is that the best strategy for generators in constrained regions with inelastic demand is to withhold to raise prices. Consonant with this finding, most of the surplus gains from new transmission accrue in *exporting* regions, whose sellers are able to supply more and at higher prices. Importing regions have modest net gains in surplus because undercutting sellers' market power and hence surplus offsets the gains to the buy side of the market from lower prices and greater quantity.

A second finding is that these gains exceed the costs of the infrastructure needed to increase transmission capacity. I compare the social benefits, or increased surplus, from transmission expansion to the costs of building the needed infrastructure. Because transmission investment is subject to cost-plus regulation ample data on the costs of existing transmission system elements is available from regulatory rulings. I apply this regulatory data on the cost of building grid elements to proposed grid expansion plans, in order to estimate the investment cost needed to relieve congestion at the margin. Expansions of transmission capacity into the North and South regions have estimated benefit-cost ratios of 1.63 and 3.50, respectively, indicating that greater transmission capacity between regions would increase social surplus.

This paper contributes to the literature on the determinants of market power in electricity markets. One line of studies of market power uses observed cost data to simulate market prices and quantities and then compares these simulated market outcomes to observed outcomes.[2]

[2] Wolfram (1999) finds prices in the UK market above cost but below the predictions of most oligopoly models. Borenstein et al. (2000) find that market power in California's restructured wholesale electricity market resulted for 59% of the nearly $7 billion rise in expenditures between 1999 and 2000. Bushnell et al. (2008) show that vertical arrangements are an important reason why these high prices do not generally obtain in U.S. markets.

This paper follows a parallel stream of literature that instead backs out marginal cost from observed bidding behavior and estimates or models the impact of changes in market structure (Wolak, 2003, 2007; Gans and Wolak, 2008; Reguant, 2011). Transmission constraints as a source of market power have been less studied empirically. Borenstein et al. (2000) study the effects of transmission capacity in a Cournot model and find that small changes in line capacity can have large competitive effects. Wolak (2012) bounds the competitive effects of transmission constraints in the Alberta market by predicting in reduced-form the offers strategic suppliers would have made, if lower congestion had raised the elasticity of residual demand they faced.[3] The closest antecedents to this paper are Wolak (2003) and Reguant (2011) with respect to estimation and Neuhoff et al. (2005) and Xu and Baldick (2007) with respect to the counterfactual treatment of congestion. This paper extends the literature by explicitly incorporating the structure of the transmission grid into the estimation of costs and counterfactual market outcomes. Knowledge of the relevant transmission constraints and a simple but non-trivial network structure allow me to model exactly how congestion enters optimal bids and how bids would change were transmission capacity expanded.

With respect to infrastructure more broadly, there is a growing development literature on the market and welfare effects of many types of investment. On electrification, Lipscomb et al. (2013) finds that electricity increases labor productivity, housing values and general development, and Dinkelman (2011) that access to electricity increases the market labor supply of women. On transport and information technology, railroads lower internal trade costs and raise income and mobile phone towers improve market efficiency by lowering the cost of information about prices (Donaldson, 2010; Jensen, 2007). Banerjee et al. (2012) find that access to transportation networks between the major cities in China increases local output, though not growth. I focus on firms' strategic response to infrastructure as a key determinant of surplus in the power market. Knowledge of the cost and demand structure for wholesale electricity enable me to calculate unusually comprehensive estimates of the net surplus gains from investment and the share of these gains due to increased competition.

The rest of the paper runs as follows. Section 2 discusses the day-ahead market in the context of the Indian power sector and the nature of transmission congestion. Section 3 intro-

[3] A range of other empirical electricity papers have noted the importance of congestion in the markets under study without explicitly analyzing congestion (Hortacsu and Puller, 2008; Bushnell et al., 2008; Reguant, 2011; Allcott, 2012). The empirical literature on congestion in operations research has focused on solution concepts for complex transmission networks (Hobbs et al., 2000).

duces the data. Section 4 introduces a model of supplier bidding and a related counterfactual model of supply and Section 5 describes the estimation strategy. Section 6 presents estimated firm costs. Section 7 presents the estimated benefits and costs of counterfactual transmission expansions and Section 8 concludes.

2 The Indian electricity sector

The Indian electricity sector is characterized by persistent imbalances. Peak demand exceeded supply by 18% in 1996, 13% in 2002 and 13% in 2011, leading to widespread power rationing (Thakur et al., 2005; Central Electricity Authority, 2011a). A combination of artificially low agricultural and retail tariffs and poor incentives for investment in generation have sustained this gap and made electricity supply an extremely unprofitable business (Wolak, 2008). The Electricity Act of 2003 was a major reform intended to correct some of the structural problems with the electricity sector in India and to create a larger role for market forces. This reform touched on nearly every aspect of electricity generation, transmission and distribution but was particularly meant to foster competition and private supply by opening access to the power grid (Thakur et al., 2005). The Central Electricity Regulatory Commission sets the terms for grid access and regulates power trade. The Act sanctioned wholesale markets for electricity and a day-ahead market, which gets its name for hosting trade one day-ahead of when the power is to be delivered, opened in 2008 on two private power exchanges.

The following subsections place the day-ahead market, the focus of this paper, in the context of the Indian electricity sector. Subsection (a) describes the basics of generation and ownership in India and subsection (b) the different ways in which power is traded. Subsection (d) says how the day-ahead market clears. Subsections (c) and (e) cover transmission capacity and how it affects power trade in the day-ahead market.

(a) Generation and Ownership

The peak generation in India of 110 GW on capacity of 187 GW in 2010, serving about 900 million grid-connected customers of a population of 1.2 billion, is comparable to the 127 GW peak on 167 GW of capacity in the Pennsylvania-New Jersey-Maryland market, which serves 51 million people (Central Electricity Authority, 2011a; Central Electricty Authority, 2012; International Energy Agency, 2011). Thermal plants generate the bulk of electricity: in 2010-11, coal plants generated 69.3% of the country's electricity, gas 12.1%, and hydroelectric 14.1%, with the balance from nuclear and imports (Central Electricity Authority, 2011b). Aside from the formal power sector, India also has a large number of so-called captive generating units owned by particular industrial, commercial or residential facilities. The total captive industrial generation capacity was about 25 GW in 2010 (Nag, 2010).

Electricity supply is dominated by state actors but the role of the private sector has recently grown. In 2010-11, the central government held 37.2% of generating capacity in the power sector, state governments 48.8% and private producers 14.0% (Central Electricity Authority, 2011b). The short-term electricity markets, described in detail below, have private sector participation far above the private share in generation overall. Large state producers sell most of their capacity through long-term physical contracts well in advance of delivery, whereas many private plants wait to sell until closer to delivery. Thus in the day-ahead market, for example, state utilities provided 20% of cleared sell volumes in 2009 and only 7% in 2010 (Author's calculation). Aside from firms devoted to private power, industrial units in other businesses commonly buy and sell power in the short-term wholesale market from their captive capacity.

(b) Segments of the Wholesale Electricity Market

There are three ways to trade wholesale electricity in India: bilateral contracts between buyers and sellers, the day-ahead market and a real-time balancing mechanism called unscheduled interchange. These segments differ, among other areas, in when electricity is traded relative to the date of delivery, how prices are set and regulatory limits on trade. While the empirical analysis treats the day-ahead market in isolation, the place of the day-ahead market among the other market segments is basic to understanding what this isolated treatment assumes.

I consider the market segments moving forward in time towards the date when electricity is physically traded. Most trade happens through bilateral contracts set more than one year in advance of delivery, which are called long-term. In fiscal 2010, 90% of the total electricity generation of 809.45 TWh was traded on long-term contracts, typically between state-owned generators and distribution companies for a large share of a generator's output (Central Electricity Regulatory Commission, 2011). The remaining trade, less than one year in advance of delivery, is called short-term. Bilateral contracts set less than one year in advance of delivery, called short-term contracts, comprise a further 5% of generation. These contracts are mediated by power traders and most often apply to daily or monthly blocks, though they can apply to any set of hours. The last opportunity for *scheduled* power trade is the day-ahead market, which handles 2% of generation. Scheduled power is reported to the system operator and traded on the day of delivery along with a balance of about 3% of generation not scheduled, which is demanded and supplied in real time at administered prices through a mechanism called unscheduled interchange (UI). I describe this mechanism in detail in Appendix A.

While the share of power traded in the day-ahead market (2%), and indeed in all short-term segments together (10%), is small, these figures are hard to compare to the share of short-term trade in other power markets. In the PJM (United States), NEM1 (Australia) and Spanish markets, 90%, 88% and 91% of physical output has already been covered by financial contracts by the time power is traded in the spot market, meaning that the generator offering power is not exposed to the spot market price for that output (Allcott, 2012; Wolak, 2007; Reguant, 2011). Due to restrictive financial regulation, India has no forward financial contracting tied to electricity spot prices. Thus suppliers in the Indian market day-ahead market earn the day-ahead (spot) price on their entire cleared offer.

Buyers and sellers arbitrage between the short-term contract, day-ahead and UI segments, but these markets do not offer perfect substitutes. Power on the three platforms is traded at different times in advance of delivery and these trades are subject to different risks.[4] There are also regulatory limits to arbitrage, described in the Appendix A (a), between the day-ahead market and unscheduled interchange, designed to prevent sellers from withholding power from the schedule and supplying it through UI instead. The overall picture of short-term power trade is then of closely but not perfectly integrated markets where arbitrage is easier for buyers than for sellers.

[4] The prices of electricity transacted on the power exchanges in fiscal 2010 averaged INR 3470/MWh, lower than the prices through contracts (INR 4790/MWh) or UI (INR 3910/MWh). These differences may reflect the lower risk of congestion for contracted power relative to the power exchanges, which clear after much transmission corridor has already been booked, and the convenience of UI in responding to short-term demand shocks.

(c) Transmission Capacity and Charges

Power that is traded in any platform must flow through the electricity grid. The high-voltage, long-distance transmission lines that carry power between regions have physical limits on how much power they can carry, determined by engineering standards. These physical limits are not the last word on the declared capacity of a line: the system operator, here the National Load Dispatch Centre (NLDC), accounts for externalities in the power grid and a reliability margin in determining how much power can flow on various paths. The transmission capacity set between regions is then allocated in a largely administrative manner prioritizing first long-term trade, then short-term contracts and lastly the day-ahead market (Central Electricity Regulatory Commission, 2008a). This allocation is described in the Appendix A. The net effect of the allocation process is that the day-ahead market becomes the residual claimant on transmission capacity across the system and is greatly exposed to transmission congestion.

The pricing of transmission does not reflect its scarcity. In the Indian market, transmission charges are flat, "postage stamp" charges that apply to use of the grid and transmission across regions, regardless of the available capacity at the time of use.[5] I neglect these transmission charges in the analysis below as they are small, about 4 percent of the mean energy charge over the period considered, and would not change in any counterfactual scenario. Suppliers in the power market with very long-term supply contracts have effective rights to a share of aggregate transmission charges, as a part of the charges paid by short-term customers are used to reduce the charges to long-term suppliers. As these aggregate rebates are not related to what lines are being used or how constrained they are, they are not likely to induce generators to alter supply decisions in the energy market to lessen their transmission charges.

(d) The Day-Ahead Electricity Market

The day-ahead market is a double-sided auction conducted every day for each of 24 hourly blocks the following day.[6] Bidders can submit both single bids, which are functions from price

[5] During the period of study, for bilateral contracts, the selling party was responsible for a charge of INR 80/MWh for connecting to the national grid and an additional INR 80/MWh for each region through which the power traded is to flow, up to INR 240/MWh for wheeling through one or more regions (Central Electricity Regulatory Commission, 2008a). On the power exchange, transactions are subject to comparable transmission charges of INR 100/MWh separately for the buyer and seller.

[6] The market is actually run on two separate power exchanges, the Indian Energy Exchange (IEX) and Power Exchange India Limited (PXI). As IEX has over 90% market share, among the two exchanges, I study bidding on this exchange alone throughout the paper. This focus will somewhat understate the costs of congestion.

to quantity for a single hour, and block bids, which specify the maximum willingness-to-pay of a buyer or minimum willingness-to-accept of a seller on average over a continuous block of hours. Figure 2, Panel A shows an example of the unconstrained market clearance in a single hour, January 26th, 2010, hour 17 (16:00-17:00). The clearing price is the least price at which supply and demand intersect. The clearing volume is the lesser of the supply and demand volume at the clearing price.[7] The supply and demand curves have been shifted out by the volume of cleared block bids.[8] Blocks are a relatively small part of the Indian market and, while I incorporate blocks in the market clearance throughout, I will take them as exogenous in the counterfactual simulations.

(e) Market Clearance with Transmission Constraints

The day-ahead market is the best channel through which to study the role of congestion in the Indian market as it is the only segment to directly price the scarcity due to congestion. The simple structure of the regional grid makes the day-ahead market well-suited to the study of congestion. As shown in Figure 1, Panel A, the power exchange designates bids as coming from one of ten subregions. I study congestion in the six regions—North, East, Northeast, West, South 1 and South 2—for which transmission constraints have ever bound.[9] Figure 1, Panel B shows a schematic of these six regions and the transmission links between them. The actual physical infrastructure underlying the grid is more complex than shown here, but this structure represents the binding links in the system very well and is therefore used by the system operator to designate available transmission capacity, check for binding transmission constraints and report these constraints to the exchange. The West and East regions form a kind of central core and are seldom constrained in sending power to one another. These core regions are connected, via separate links, to the demand centers of the North and South 1 regions. The South 2 region is further removed from the core and only accessible via wheeling (i.e., transshipment) of power through South 1. The Northeast region, a source of hydropower,

[7] As discussed in the Appendix, the Indian Energy Exchange actually uses piecewise-linear bids that are strict functions from price to quantity. Bidders in practice use these functions almost exclusively to closely approximate step functions (strictly correspondences) with constant quantities for a range of prices and then discrete increases in quantity over the minimum allowed price tick. I assume bids to be of a true step form throughout and do not use the linear interpolation of the exchange, which makes a trivial difference in clearing prices.

[8] Block bids are cleared by an iterative algorithm described in the Appendix.

[9] Two of these, South 1 and South 2, are technically subregions of the South region but I will refer to them as regions.

is linked to the core through the East.

The power exchanges manage congestion with market-splitting.[10] The basic idea is to iteratively separate areas with binding constraints and clear them separately. The exact algorithm used is not published and I recreate it here. The market is first cleared unconstrained amongst all regions. I then compare the net demand of each combination of regions and the implied power flows on the grid to both margin constraints, which specify the maximum allowable imports or exports of a region (node), and path constraints, which specify the maximum flows on each path (link) in each direction. If any area violates any constraint, I separate the area with the largest violation on the importing side and declare its imports to be the value of the binding constraint and the exports of the complementary area likewise. I then clear each area separately and check for constraints again, repeating this process until no constraints bind.[11] Bidders in each constrained area receive the area-clearing price in that area.[12]

Figure 3 shows the application of the market-splitting algorithm to the same hour for which Figure 2, previously discussed, shows the unconstrained clearance. The unconstrained solution implied a flow to the North region of 571 MW, in excess of its import capacity of 171 MW. The North region was therefore constrained apart from the rest of the grid and these two areas cleared separately, as shown in Figure 3, Panels A and B, with imports added to supply and exports to demand in each area. The importing North region has a clearing price about INR 1000/MWh above the other regions and no further constraints bind once these areas are cleared separately. The Appendix shows that my recreation of this algorithm matches area-clearing prices very well.

3 Data and Study Sample

The analysis uses confidential data from the Indian Energy Exchange (IEX) and the system operator (NLDC). To my knowledge there are no other studies that use comparable data on the power market in a developing country.

[10]Market-splitting is a zonal pricing method similar to that used in ERCOT (Texas) until 2010 and still used in the Nordpool.

[11]The binding of an internal constraint may relax an outer constraint. E.g. if South 1 and South 2 are initially constrained, and the clearing amongst these regions implies that South 2 is further constrained from South 1, I constrain South 2 from South 1, relax the outer constraint of South 1 from the core and iterate.

[12]The difference between selling prices in exporting regions and buying prices in importing regions is retained by the system operator, under supervision of the regulator, in a Power System Development Fund. As of March 31, 2011 this fund held INR 4.57 billion (USD 91 million) in congestion revenues.

From the exchange, I use the bids and offers from participants in the day-ahead market. Bidders submit these bids as piecewise-linear functions from price to quantity between up to 64 points, from the price floor of INR 0/MWh to the ceiling of INR 20000/MWh. Most bidders use few segments and nearly all segments submitted are flat, so that the bids are step functions in practice.[13] Bidders may offer fewer steps than allowed because marginal cost is closer to constant over the relatively small range of offered quantity. As described in the Appendix A, I take the step-function structure of the bids actually submitted as given and apply the share-auction framework for modeling bids in terms of incremental quantities submitted at each step (Wilson, 1979).

From the system operator, I use transmission constraints as supplied to the exchange on the afternoon of the day of bidding. These constraints include, for every hourly block, both margin constraints on the maximum exports and imports permissible for each regional node and path constraints on the maximum flows over each inter-regional path in each direction.[14]

I limit the sample to the inclusive period from November, 2009 through April, 2010 to study the bidding response to congestion within a constant regulatory framework. In parts of September and early October, 2009, the day-ahead market was under close regulatory scrutiny and a price cap of INR 8000/MWh was imposed and often bound. Such a binding cap would invalidate the first-order approach to bidding optimality used in the estimation below. In May, 2010, the schedule of administrative prices for Unscheduled Interchange was revised. As this schedule may influence the opportunity cost of buying and selling power in the day-ahead market for many bidders, the structure of costs underlying bids could have changed at this juncture.

(a) Prevalence of Congestion

Congestion occurs when one region or set of regions cannot import enough power to clear at the same price as the rest of the grid. During the sample period—indeed, during the life of the power exchanges to date—congestion has been frequent and had a large impact on market prices. The most common patterns of congestion are for the North region or some

[13] This limited use of a complex strategy space occurs in other markets (Hortacsu and Puller, 2008).

[14] During the study period, the system operator told the power exchanges what the constraints were over the course of the day only if congestion occurred in any hour of the day in the unconstrained solution. On 7 of 181 days in the sample, no congestion occurred, so the bootstrap simulations and counterfactual will assume that the market was unconstrained on these 7 days.

combination of the South 1 and South 2 regions to be import constrained with respect to the central core of the East and West regions. Figure 4 shows the relationships between inter-regional power flows and regional price differences between the East and North regions (Panel A) and the East and South 1 regions (Panel B). The horizontal axis shows the flow between regions, with positive flow indicating the net supply from the East region, and the vertical axis shows the difference between the North or South 1 price and the East price. When the flow between regions is constrained, the constrained areas including each region are cleared separately, and the market-clearing prices in the two regions will differ. Any positive price difference between regions in the figure thus indicates that flows are bound by a transmission constraint. As shown in Panel A, low levels of constrained flow lead to price differences of up to INR 6000/MWh, larger than the average market price. When more corridor is available, the greater flow between regions eliminates or reduces the price difference, creating the negative correlation between price differences and constrained flow in the figure.

Table 2 summarizes the prevalence of congestion during the sample period by comparing the prices of each pair of regions, which only differ if the regions are separated by constrained links. Panel A shows the percentage of the 4344 hours (= 24 hours $\times$ 181 days) over the sample period during which the price in the row region is higher than the price in the column region. The North region is constrained away from the Northeast, East and West regions over 18% of the time during this period. The South 1 region is import constrained with respect to this core 23% of the time and the South 2 region 26% of the time, as the link between the South 1 and South 2 regions also occasionally binds. These constraints create large differences in market prices across regions. Panel B shows the row region price less the column region price, conditional on the row region price exceeding the column region price. The average price difference between the North and East regions, i.e. over the scatter plot of points above the horizontal axis in Figure 4, Panel B, is INR 1688/MWh, and between the South 1 and East regions 1655/MWh, each about 38% of the mean unconstrained market-clearing price of INR 4352.90/MWh. In a small number of hours the West and East are import constrained with respect to the Northeast.

4 Model of Supplier Bidding with Transmission Constraints

To measure how transmission constraints affect market outcomes, I estimate firm costs and compute counterfactual market outcomes at different levels of these constraints. Firm costs are estimated from supply bid functions using a first-order approach accounting for the effect of transmission constraints on residual demand. This estimation approach, pioneered by Guerre et al. (2000), was adapted for electricity markets by Wolak (2003) and has been applied by Reguant (2011) to study complex bidding in the Spanish market and Allcott (2012) to study real-time pricing in the PJM market.

Though bidding in the day-ahead market allows price-quantity functions, in the counterfactual simulations I apply a Cournot model wherein strategic bidders offer fixed quantities. Solving the full supply-function equilibrium in a constrained network is computationally difficult (Wilson, 2008); even without constraints equilibria are numerous and stable ones hard to find (Holmberg, 2009; Baldick and Hogan, 2002). In the Indian market, limiting firm strategies is preferable to limiting the number of firms, as a way of simplifying the model solution, since there are many firms and they each use only a small part of the allowed strategy space in practice.

The Indian market is also well-suited to the Cournot model, amongst electricity markets, as a relatively elastic demand side at the wholesale level leads to reliable price discovery in the model (as opposed to the case of both demand and supply being nearly inelastic, where the market price can vary wildly). Cournot models have been widely used in empirical analysis of restructured electricity markets and fit market outcomes well when accounting for market structure and institutions like vertical integration (Puller, 2007; Bushnell et al., 2008). The simplicity of Cournot strategies allows for more accurate modeling of transmission constraints in particular (Cardell et al., 1997; Jing-Yuan and Smeers, 1999; Willems, 2002; Neuhoff et al., 2005).

(a) Model

The model assumes that strategic firms maximize expected profits by submitting supply functions to the exchange. Firms face uncertainty over the bids of other firms and demand and submit their bids to the market one day ahead for each hour of the following day.

The offered supply of firm i in region g and time period t is represented by a supply function $q_{it}(p)$.[15] The firm submits a supply function to maximize profits given the expected distribution of other firms' bids and demand, accounting for transmission constraints. The firm's problem is:

$$max_{\mathbf{b_{it}},\mathbf{q_{it}}} \mathbb{E}_{\sigma_{-it}} \left[q_{it}(p)p - C_i(q_{it}(p)) \right],$$

where the supply function $q_{it}(p)$ depends on the price ticks b_{itk} of each individual bid and $C_i(\cdot)$ is i's total cost of production. The market clearing condition is that quantity supplied equal residual demand at the market-clearing price, $q_{it}(p) = D_{it}^{rg}(p|\sigma_{-it}, \mathcal{L}_t)$, where $D_{it}^{rg}(p|\sigma_{-it}, \mathcal{L}_t)$ is the residual demand facing firm i in region g, σ_{-it} are the strategies of bidders other than i, including demand bids, and $\mathcal{L}_t$ the set of transmission constraints.

Taking the derivative with respect to each bid-tick price, a necessary first-order condition for profit maximization is:

$$\mathbb{E}_{\sigma_{-it}} \left[\frac{\partial p}{\partial b_{itk}} \left(q_{it}(p) + \frac{\partial D_{it}^{rg}(p|\sigma_{-it}, \mathcal{L}_t)}{\partial p} (p - C_i'(q_{it}(p))) \right) \right] \Bigg|_{p=b_{itk}} = 0, \tag{1}$$

after substituting using both the market-clearing condition and the implicit function theorem.[16] This is a Lerner pricing rule whereby the firm sets prices at marginal cost plus quantity over a weighted expectation of the slope of residual demand. The weights are the slope of the market price in the bid price and can be thought of as the probability that a given bid tick sets the market price. A greater slope of residual demand reduces the optimal markup at each given quantity supplied.

(b) Constrained Residual Demand

The residual demand faced by each firm will depend on both the bids of other firms and the amount of transmission capacity. The residual demand facing firm i in region g at price p is

[15] This supply function is a continuous approximation to the step supply correspondence $\hat{q}_{it}(p) = \sum_k q_{itk} \mathbf{1}\{b_{itk} < p\} + \alpha q_{itj} \mathbf{1}\{b_{itj} = p\}$ for $\alpha \in [0, 1]$. The firm supplies the incremental quantity q_{itk} at all prices strictly above b_{itk} and may offer any part α of an incremental quantity when the market price exactly equals the price of the bid tick, with the exact quantity supplied determined by market clearing.

[16] See the Appendix for further details.

written as:

$$D_i^{rg}(p|\sigma_{-it}, \mathcal{L}_t) \quad = \quad D^g(p, \sigma_{-it}) - \sum_{j \neq i, j \in \mathcal{A}_g(p|\mathcal{L}_t)} q_j(p, \sigma_j) - \mathcal{F}(\mathcal{A}_g|p, \mathcal{L}_t).$$

The residual demand that a bidder faces in their own region is the demand in that region, less competing supply bids within the same constrained area, which are sensitive to price, and the fixed quantity that the region is importing, which is not sensitive to price at the margin. I collect own-region demand bids into D^g, letting $j = \{j : j \notin g | q_j > 0\}$, with positive q meaning supply. I designate by $\mathcal{A}_g(p|\mathcal{L}_t)$ the set of regions to which region r is connected by unconstrained transmission lines at a price p and given line capacities $\mathcal{L}_t$, and call such a group of regions an area. These connections may be direct or indirect, through another region; all regions connected by any unconstrained path form an unconstrained area. Let $\mathcal{F}(\mathcal{A}_g|p, \mathcal{L}_t)$ be the net constrained flows into area $\mathcal{A}_g$ at price p and line capacities $\mathcal{L}_t$.

The derivative of the residual demand for this firm with respect to price is

$$\frac{\partial D_{it}^{rg}(p)}{\partial p} \quad = \quad \frac{\partial D^g(p, \sigma_{-it})}{\partial p} - \sum_{j \neq i, j \in \mathcal{A}_g(p|\mathcal{L}_t)} \frac{\partial q_{jt}(p, \sigma_j)}{\partial p},$$

assuming that the constraints are not exactly binding, so that a small change in price does not change $\mathcal{A}_g(p|\mathcal{L}_t)$. If the set of binding constraints does not change, then constrained flows $\mathcal{F}(\cdot)$ are also fixed. This assumption appears reasonable given the uncertainty faced by bidders as it is unlikely constraints will exactly bid for a given realization of demand and other supply bids. The smaller is the constrained region $\mathcal{A}_g(p|\mathcal{L}_t)$, the weakly smaller (closer to zero) is the residual demand slope bidder i faces, as all bids outside of $\mathcal{A}_g$ contribute a fixed amount of imports or exports. The slope of residual demand for each bidder, for a given realization of demand and other supply bids, comes from only those bids with an open link to that bidder's region.

The constrained area $\mathcal{A}_g(p|\mathcal{L}_t)$ is determined using the market-splitting algorithm employed by the power exchange and described in Section 2. Using this area assumes that bidders solve forward the congested area to which they will belong for possible realizations of other bids but do not change their bids to manipulate this area. In principle there may be multiple equilibria with different constrained areas. This prospect does not affect estimation using the local first-order necessary conditions but may matter for counterfactual simulations, as discussed in Section 4 (c) below.

Constraints do not unambiguously raise bid prices or reduce offered quantities. The overall effect of transmission constraints on supply bids will depend on the shape of the constrained and unconstrained residual demand curves. Although the residual demand slope at a given price unambiguously falls when a region is constrained, the distribution of equilibrium prices in a region will change as constraints bind. A bidder may therefore expect bid ticks higher (lower) in the distribution to be marginal if its region is import (export) constrained and will set markups based on the slope of residual demand in that range of prices, instead of in the range of prices anticipated without congestion. For example, a supplier in an import-constrained region may face more elastic demand at the high area-clearing prices expected to be marginal when constrained, inducing an expansion of quantity supplied or lowering of price for any given quantity. Conversely, a supplier in an import-constrained region gaining a greater market share and serving greater inframarginal quantity than when unconstrained would tend to lead to increases in mark-ups, magnifying the effect of lower residual demand slope.

(c) Cournot Counterfactual

To simulate counteractual outcomes I use a Cournot model for a set of strategic firms. I take all sellers in the North and West regions with greater than a one-percent share of total offered sell volume to be strategic and treat the other bidders as a competitive fringe. The market is not very concentrated; this set of thirteen strategic firms covers 71% of all offered sell volume. I consider only strategic suppliers in the North and West regions because these regions are important in themselves, as large load and supply centers, respectively, and form relatively liquid markets when constrained, making a smooth approximation to the residual demand curve in each region reasonable.

Firm costs are assumed constant over the sample period and will be held constant in counterfactual simulations while expanding transmission capacity. This method assumes either that costs do not depend on conditions in other market segments or that, to the extent they do, these conditions would not change with additional transmission capacity in the network. The primary concern is that the option of supplying in real-time is a common opportunity cost of supply in the day-ahead market, and that the value of this option may change if transmission expansions change demand and supply in the balancing market. Note that the quota-like limits on real-time balancing (UI) for suppliers, described in Section 2 and the Appendix, constrain large suppliers from offering more in real time. These constraints mean that the marginal costs of supply in the day-ahead market are private marginal costs, rather than a common expectation of what the real time price will be the next day.

Consider a set of strategic firms i with marginal costs γ_i facing a residual demand curve $D^g(p|\sigma_{-it}, \mathcal{L}_t)$ with twice-continuously differentiable inverse residual demand curve $\tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L}_t)$, where Q^g is aggregate strategic quantity offered in region g by all strategic firms together. The derivative of profit with respect to the seller's offered quantity q_{it} is:

$$f_{it}(q_{it}) = \tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L}_t) + q_{it}\tilde{P}^{g\prime}(Q^g|\sigma_{-it}, \mathcal{L}_t)) - \gamma_i.$$

Necessary and sufficient conditions for an equilibrium set of quantities are that for all strategic sellers i:

$$\begin{aligned} q_{it} \in (0, \overline{q}_i) \quad &\perp \quad f_{it}(q_{it}) \neq 0 \\ q_{it} = 0 \quad &\perp \quad f_{it}(q_{it}) \geq 0 \\ q_{it} = \overline{q}_i \quad &\perp \quad f_{it}(q_{it}) \leq 0. \end{aligned}$$

Here $\overline{q}_i$ is the maximum quantity that a strategic seller can offer, due to capacity constraints. If the seller produces an interior quantity, between zero and their constraint, then it must be that the derivative of profits with respect to quantity at that point is zero. Similarly, if the seller produces nothing this derivative must be negative, else they would increase quantity, and if the seller produces at their quantity constraint this derivative must be positive, else they would either decrease quantity. Similarly to Bushnell et al. (2008), I solve this problem with the sequential linear complementarity problem approach of Kolstad and Mathiesen (1991) using the PATH algorithm on each iteration (Dirkse and Ferris, 1995). Sufficient conditions for the uniqueness of Cournot equilibria generally require pseudoconcavity of profit functions (Kolstad and Mathiesen, 1987). Given constant marginal costs, the profit functions must inherit this property from the demand function. I discuss uniqueness more below.

An example of the solution to the model is shown in Figure 2, Panel B. Panel A is the actual market clearance, previously discussed, and Panel B the Cournot model simulation for the same hour. In Panel B the increasing solid curve represents the marginal cost curve for strategic suppliers (from my estimates). The decreasing solid curve is the residual demand curve, composed of demand bids and fringe supply bids, and the dashed-and-dotted line is a smoothed representation of the inverse residual demand. The smoothing is over quantity with a bandwidth equal to ten percent of the quantity range of the residual demand curve. The vertical line is the equilibrium strategic quantity offered by the strategic suppliers, at which the above conditions are satisfied with respect to the smoothed inverse residual demand, as further expansion of quantity would steeply push down the market price. The market-clearing price for the simulation is the intersection of the strategic quantity with the actual, not smoothed, residual demand curve and in this case matches the actual clearing price seen in Panel A.

The above problem applies to the residual demand curve faced by each seller within their own constrained area, a group of regions constrained from the grid but themselves clearing at the same price. The solution algorithm mimics the market-clearing algorithm in order to determine what constrained area each seller is bidding within, first solving for the unconstrained solution with endogenous bids and then breaking off constrained areas and solving within each constrained area separately, shifting residual demand by the constrained level of imports or exports. Simulations of market outcomes use the realized residual demand curve, composed of all demand bids and fringe supply bids, to solve for market equilibrium. The strategic quantities offered are therefore *ex post* optimal with respect to the smoothed inverse residual demand curve.

The Cournot model used does not theoretically guarantee a unique equilibrium here, for two reasons, but both of these reasons turn out not to produce multiple equilibria in the market studied. The first reason the equilibrium may not be unique is the presence of transmission constraints. Transmission constraints can produce multiple equilibria, with lines congested in different directions, or leave no pure-strategy equilibria at all. In markets with asymmetric firms and demand across regions, a pure-strategy equilibrium of the Cournot model will virtually always exist: the condition necessary for two regions is only that the two regions have different monopoly prices (Borenstein et al., 2000). The asymmetry in the

Indian day-ahead market between a relatively low-priced central core, of the West and North region, and a high-priced periphery, of the North and South, suggests there will be a single pure-strategy equilibrium, as it will not be worthwhile, or even possible, for the suppliers in power-scarce regions to congest the line outwards in order to gain market share from relatively abundant regions.

The second reason that the equilibrium may not be unique is that the residual demand curve here is not always pseudoconcave. Because I smooth inverse residual demand but do not otherwise restrict its shape, it can alternate between concave and convex regions at different quantities, which may, but will not necessarily, admit multiple equilibria at different clearing volumes. I discuss the empirical relevance of equilibrium selection in Section 6 and find that the equilibrium is basically always unique.

5 Estimation Strategy

The object of estimation is the marginal cost of supply for firms in the day-ahead market. I apply the generalized method of moments (GMM) to the first-order condition for optimal bids to estimate these costs. The marginal cost of each firm is a behavioral cost, in the terminology of Wolak (2007), in the sense that it may include not only the technological costs of generation but also the opportunity cost of selling in the day-ahead market. This distinction is especially important in the Indian market where the alternative to selling in the day-ahead market, for some bidders, may be to generate power for industrial production.

To approximate the uncertainty faced by firms in the day-ahead market I resample demand bids and the supply functions offered by other firms. Bids from all other bidders are drawn in complete days at the region-by-bidder-type level, where regions are the six regions discussed in Section 2 (c) and the bidder types are State Generating Companies, Private Generating Companies, Distribution Companies and Industrial Firms. Other bidder-days are drawn with weights in proportion to a triweight kernel in distance from the day for which uncertainty is being simulated, with a bandwidth is 14 days. This resampling method is a block bootstrap which allows for arbitrary correlation among bids within region-bidder-day blocks. When there is a single bidder of a given type in a given region, this procedure maintains its identity, while when there are many bidders, such as industrial consumers on the demand side, it replicates the uncertainty caused by such firms dropping in and out of the market.

The estimation moments are the empirical analogue of the first-order condition (1):

$$m_{ikh}(\gamma_i) = \frac{1}{|H(h)|S} \sum_{t \in H(h)} \sum_{s=1}^{S} \frac{\partial \tilde{p}^s}{\partial b_{itk}} \left(\tilde{q}_{it}(b_{itk}) + \frac{\partial \tilde{D}_{it}^{rgs}(b_{itk}|\sigma^{\mathbf{s}}{}_{-i}, \mathcal{L}_t)}{\partial p} (b_{itk} - C_i'(q_i(b_{itk}))) \right),$$

where $s \in \{1, \ldots, S\}$ are bootstrap iterations, $H(h)$ is the set of times with hours equal to h, and a tilde indicates a smoothed function. I take $S = 100$. Every bootstrap draw of bids $\sigma^{\mathbf{s}}{}_{-i}$ generates a residual demand curve that may differ both in its component parts and in the regions over which it is aggregated, depending on what transmission constraints the bids drawn induce to bind. The moments reflect uncertainty over the composition of one's own constrained area as well as others' bids. As bids are represented discretely, the derivative of residual demand, a key determinant of mark-ups, is strictly equal to zero at almost all prices. I therefore smooth the residual demand function over prices with a normal kernel to approximate this derivative and the probability that a bid tick sets the market price (Following Wolak (2003); see Appendix B).

The parameters of interest are the marginal cost functions for each bidder. I specify $C_i(q) = \gamma_{i0} + \gamma_i q$ so that marginal costs are constant at γ_i. Empirical papers on electricity markets have used a range of specifications for marginal cost suited to the question at hand.[17] Given the small range of supply from most participants in the day-ahead market, relative to other markets or their own generation portfolios, constant marginal costs are likely to be a good approximation. Moreover, the average sell bid described in Table 1 has only about two bid ticks and only three strategic sellers average over three steps per offer. This limits the variation available to estimate any slope of marginal cost for most bidders.

I estimate the marginal cost parameter γ_i for each strategic seller by summing moments $\overline{m}_{iko}(\gamma_i) = \sum h \in o m_{iko}(\gamma_i)$ over four equal hourly blocks o and solving for the GMM estimator that minimizes the inner product of these moments.

$$\hat{\gamma}_i = \arg\min_{\gamma} \overline{m}_{iko}(\gamma_i)' \overline{m}_{iko}(\gamma_i)$$

[17] E.g., Gans and Wolak (2008) use constant marginal costs to study vertical integration and the models reviewed in Neuhoff et al. (2005) that incorporate transmission constraints mostly use piecewise constant marginal costs, whereas Reguant (2011) estimates linear marginal costs with adjustment cost to capture dynamic firm decisions important to the study of complex bidding.

One concern with this estimation strategy is that the residual demand a bidder faces may be endogenous with respect to econometric errors in their bid. For example, suppose a bidder that has a positive cost shock for a given hour and offers at a high price, and is then marginal in a less elastic region of the demand curve. The estimation moment will infer from the low elasticity of demand that the bidder has a high mark-up and thus low cost, whereas the bidder actually was high cost because causality ran from bid to elasticity, and not vice versa. As a robustness check, I discuss in Section 6 alternative estimates that use temperature at the region-by-hour level from the day of bidding to instrument for the estimation moments.

Standard errors are bootstrapped to account for both statistical and simulation error. I bootstrap one hundred samples, where each sample draws with replacement both days from the observed sample and counterfactual market outcomes, for each sampled day, from a set of one hundred simulations of daily market outcomes. Cost coefficients are estimated for each set of days and market outcomes drawn.

I also estimate a capacity constraint for each seller as the maximum offered quantity in the market for each seller over the sample period. Sellers sometimes offering at their capacities in quantity does not invalidate the first-order conditions used in estimation, as the first-order conditions are with respect to price. All bid ticks are below the ceiling price, so bidders can always raise the price of their last unit of quantity even if they cannot offer more.

6 Results

(a) Estimated Marginal Costs

The characteristics and estimated marginal costs of strategic sellers are shown Table 3. There are four strategic sellers in the North and nine in the West. They are a heterogeneous lot, representing all of the four broad bidder types that bid on the exchange: state utilities, distribution companies, private generating companies and industrial plants. Column 3 of the table reports the market share of each strategic seller by their share of offered volume. The largest two sellers, including the largest single seller by a wide margin, at 23 percent market share, are state utilities in the Western region.[18] Industrial plants have small shares of overall

[18]The Herfindahl index for unconstrained offered volume by all sellers is 0.092.

market volume but offer significant volume of up to 250 MW in some hours.[19] The largest suppliers in the North region are distribution companies, which the Electricity Act of 2003 permitted to vertically integrate into generation (Thakur et al., 2005).

The estimated marginal costs of these suppliers are presented in column 6. The range of cost estimates is broad but reasonable. The estimated costs for individual sellers range from a low of INR 680/MWh up to a high of INR 5923/MWh, with both extremes coming from industrial plants. The opportunity cost of supply in the day-ahead market is likely to be different from the pure technological cost of generation for industrial plants, which can alternately use the power themselves.[20] Larger discoms and state utilities have estimated marginal costs in the INR 2500/MWh to INR 4000/MWh range. By seller type, the mean cost estimates in ascending order are INR 1940/MWh for private generating companies, INR 2992/MWh for industrial plants, INR 3087/MWh for distribution companies and INR 3177/MWh for state utilities.

Column (5) shows the mean quantity-weighted tick price of bids offered by each bidder, i.e. the average price at which a megawatt is offered. Comparing this column to the estimated costs implies that the average quantity-weighted markup of offered sell ticks is INR 645/MWh or 26 percent of cost. All types of bidders have markups between INR 600/MWh and INR 700/MWh. Private generating companies have similar absolute markups to other sellers, at INR 630/MWh, but lower costs and therefore larger markups in percentage terms. The estimated marginal costs are reasonable in terms of the observed bids from which they were estimated.[21]

These estimates are consistent with the available information on generating costs in India. A limitation of the data is that the bidders are anonymous. The generation technology used by each seller is thus unknown and a precise comparison of estimated costs to physical costs is not possible. I therefore benchmark the cost estimates against public data on prices paid for energy and power in the state sector (Central Electricity Regulatory Commission, 2011).

[19] Capacity of 200 MW or more is high, but not unheard of, for a captive generation facility: India had 19 plants with above 100 MW of capacity in 2004 (Central Electriity Authority, 2005).

[20] One interpretation of the low cost of supply from a single industrial seller is as reflecting power from a plant or set of plants that overbuilt captive generation capacity but needs to produce at some minimum stable load.

[21] One industrial plant has estimated costs above the weighted mean offered tick price. Given that this seller's average offers are only about half of the market-clearing price, it is likely that many of this seller's offers are too far from marginal to influence the estimated costs, which are estimated to be greater in order to fit higher offers from the same seller better.

The mean energy charges, meant to capture marginal costs, paid to state generating stations under long-term power purchase agreements in 2010, were INR 2192/MWh for coal stations not at the pit-head, INR 2193/MWh for natural gas units and INR 4668/MWh for liquefied natural gas units. These are broadly consistent with but somewhat below the costs I estimate, which is sensible given that long-term power-purchase agreements are more likely to rely on low-marginal-cost baseload plants.

Table B4 in Section B compares these baseline estimates to estimates that use lagged temperature as an instrument for the estimation moments. The baseline estimates of marginal cost are in column (2) and column (6) reports the IV estimates. The mean marginal cost estimates across all bidders rises a modest 8% in IV estimates, reducing bidder margins, and the mean absolute deviation between the baseline and IV estimates is also 8%. One bidder sees estimated costs rise above its mean bid in IV estimates. Endogeneity of bids driven by cost shocks appears a mild concern in this market, perhaps because few shocks are realized by the time offers are made, a day ahead of delivery. The effect of IV cost estimates on the main welfare results of the paper, discussed below in Section 7, is negligible.

From the estimation of marginal costs, a very high cost structure does not appear necessary to rationalize high market prices. Market prices have a mean of INR 4352/MWh and a standard deviation of 2426/MWh, and transmission constraints routinely create regional differences in price of INR 2000/MWh or more. Yet these conditions do not imply, through the model, that costs of supply are unreasonably high overall or in the constrained North region in particular. Instead, market structure, in the form of transmission constraints increasing concentration, appears to account for high prices.

(b) Counterfactual Model Fit

Before turning to counterfactual outcomes it is important to understand the fit of the constrained Cournot model in the baseline case. The overall fit of the model is good and the fit with respect to patterns of congestion and regional price differences is very good, especially considering the parsimonious specification. Table 4 compares actual market outcomes, in columns 1 and 2, with outcomes for the constrained Cournot model with the same amount of transmission capacity. The model somewhat overpredicts unconstrained quantity and therefore underpredicts unconstrained price by 15 percent (INR 665.73/MWh on a base of INR

4352.90/MWh). The model matches constrained market outcomes, the focus of this paper, extremely well. The North region is import constrained with respect to the West region 16 percent of hours in the model, as against 18 percent of hours in reality. The price difference between these regions conditional on the North price being greater is INR 1437/MWh in the model and INR 1685/MWh in the actual market clearance. The North region and West region have similar, though somewhat larger in magnitude, net demands in the model as in the actual clearance, and these net demands are similarly variable. The fit in the South 1 region is also very good; for example, the difference between South 1 and West prices conditional on congestion is INR 1647/MWh in fact and INR 2049/MWh in the model.

Two primary factors explain the model tendency to overpredict unconstrained quantities and therefore underpredict prices. First, as a baseline case I have taken the capacity constraints in every time period to be the maximum quantity offered by a seller over the entire sample period, as shown in Table 3 column (4). Sellers may not have this maximum capacity available over the entire sample period, e.g. if it was contracted out during some months. To test the importance of this idea I instead let the capacity constraint be the maximum capacity offered by a seller in a given month.[22] This increases the average price predicted by the model by INR 101/MWh to INR 3788/MWh, improving the fit. Allowing stricter capacity constraints at higher frequencies would raise predicted prices further. Second, the counterfactual model does not represent the uncertainty faced by sellers. When facing a residual demand curve of the nature of Figure 3, Panel B, where price drops off very steeply after the equilibrium quantity, introducing uncertainty would likely induce sellers to choke back quantities supplied, raising prices. Uncertainty over the residual demand curve may therefore improve the fit. I do not introduce uncertainty in the counterfactuals given that the model matches the outcomes of interest with respect to transmission congestion well already and that model scenarios will be compared to one another to determine counterfactual changes in welfare.

Equilibrium selection is decidedly not responsible for the model's overprediction of quantity. In the baseline simulation I initialize the search for an equilibrium at the point where all strategic sellers equally supply 75% of the maximum residual demand. This could in principle lead to selection of local equilibria further out on the demand curve than the actual equilibria

[22] The mean of the standard deviation of maximum capacity each month as a share of overall maximum capacity is 21 percent, a modest but significant change.

selected by firms, in accord with the discussion of Section 4 (c). I test for the importance of equilibrium selection by instead allocating strategic sellers 25% of the maximum residual demand to start. This produces an average unconstrained market price of INR 3689.49/MWh over the sample period, basically indistinguishable from the price of INR 3687.16/MWh in the baseline simulation, indicating that a different equilibrium has been found in at most a handful of hours. The two simulations also match exactly on other dimensions of congestion and market volume. That the equilibrium found by the model is basically always unique is due to the typical shape of the demand curve. In many hours, the demand curve is inelastic at low and high prices and elastic at moderate prices, as in Figure 3, Panel B.[23] In principle this can create distinct concave portions of residual demand where equilibria might be found. In practice, though, the potential equilibria higher up the residual demand curve are at very low or even negative quantities, and sellers can increase profits in this part of the curve by selling more.

7 Counterfactual Transmission Expansion

(a) Simulated Benefits of Transmission Expansion

As counterfactual scenarios I consider investments in new transmission capacity into the two most frequently constrained regions, the North and the South. Specifically I consider increasing the transmission capacity from the East to the North and South 1 regions by 400, 800 and 1200 MW.[24] Market outcomes with expanded transmission capacity are shown in Table 5. Panel A of the table considers expansion of the links leading to the North region and Panel B to the South 1 region. The top portion of each panel shows select market outcomes holding strategic bids fixed at baseline levels and the bottom level of each panel allows bids to adjust endogenously to the new level of constraints.

Expanding the North region's import capacity while holding strategic bids fixed reduces congestion sharply but increases market surplus only modestly. An expansion of only 400 MW reduces congestion from 16 percent of hours in column (1) to 2 percent of hours in column (2), and an expansion of 800 MW eliminates congestion almost entirely in column (3). The price

[23] The extreme elasticity at moderate prices comes mainly from industrial consumers that have outside options of purchasing from unscheduled interchange or from state suppliers at prices in this range.

[24] Given that the East to West link has a high capacity, it makes a negligible difference whether the expansion is from the East into the constrained regions or from the West.

difference conditional on congestion for the remaining congested hours remains fairly high. The North region increases its net demand somewhat by purchasing more from other regions; the West region net demand holds steady. Market surplus, shown in the fourth row of the top of Panel A, increases by INR 0.02 million per hour for a 400 MW expansion or greater, shown in columns (2) through (4). This increase is barely perceptible on a base of INR 3.26 million per hour. The change in surplus is a composition of an 11% increase in surplus for buyers, who in the North region get cleared at lower prices, and a 6% decline for sellers, who also get cleared at lower prices. Note that in the baseline case fully 74% of the market surplus goes to the sell side of the market during this period. This asymmetry is not only due to the generally high market prices, but is driven by the fact that buyers have outside options for the procurement of power. They therefore bid a very elastic demand curve and set the marginal price and are then often nearly indifferent to buying or not.

The welfare gains in the North region with endogenous response of strategic sellers are larger than when holding bids fixed. When bidders respond endogenously, the West region increases supply to serve demand in the North region. The share of congested hours decreases with transmission expansion, but more slowly than with fixed bids, as sellers in the West region recongest the line by offering greater quantity. For example, at a 400 MW expansion in column (2), the North price is greater than the West price in 7 percent of hours, as opposed to 2 percent of hours holding bids fixed. By 800 MW, in column (3), congestion lingers in 2 percent of hours with endogenous bids but has disappeared with fixed bids. In contrast to the case with fixed bids welfare improves overall with endogenous bids, with an increase of INR 0.16 million per hour from column (1) to column (4). Sellers are no worse off after the transmission expansion, as they increase quantity to compensate the loss of profits due to lower prices. Buyers are significantly better off. The net result is that surplus rises 5 percent when bids are allowed to adjust.

There are welfare gains from additional import capacity into the S1 region even holding bids fixed. Table 5, Panel B shows the effects of an expansion of capacity leading to South 1. The South 1 region is frequently import constrained relative to the West region, but as suggested by Figure 1, Panel B, this is in part because it is the only path of transit to the South 2 region, which is a greater source of demand and itself sometimes constrained relative to South 1. Expanding South 1 region import capacity holding bids fixed increases welfare, unlike for the North region. Buyers overall are not much better off, indicating that buyers in the South 1 and South 2 region may demand a large quantity but not at much higher willingness-to-pay than the buyers outside the South that were being cleared in the baseline case. Strategic sellers in the North and the West regions benefit from being able to serve the South region demand, which raises prices in their areas.

Transmission capacity into the South increases welfare greatly with endogenous bids. Overall surplus rises by fully 14 percent with the response from strategic bidders, as opposed to 5 percent with fixed bids, for an expansion of 1200 MW, which almost, but not quite, eliminates congestion to the South 1 region. Sellers, despite lower prices in the South, are better off for being able to serve the demand in the South region. Buyer welfare increases by 23 percent with lower prices and greater quantity. The South 1 region actually shifts from a marginal net seller to a net buyer with the capacity expansion as it is now able to consume power itself rather than sell it onward to higher-value consumers in the South 2, as had often been the case when the South 1 and South 2 regions were constrained from the rest of the grid together.

Accounting for competitive effects, then, shows that a greater expansion of transmission capacity is required to relieve congestion as strategic sellers compete in newly accessible regions. The welfare gains from transmission expansion, however, are correspondingly larger as a greater quantity gets cleared for higher-value buyers. Figure 5 summarizes the welfare gains for counterfactual increases of transmission capacity. Panel A shows expansions of capacity into the North region and Panel B into the South region. In each panel, the thin (red) lines represent surplus holding strategic bids fixed at the baseline level while the thick (black) lines represent surplus allowing strategic bids to adjust endogenously to the new level of transmission constraints. Within each scenario, the dotted line represents buyer surplus, the dashed line seller surplus and the solid line total surplus. Each surplus measure is scaled by subtracting the baseline surplus for each group and dividing by the total surplus for all groups. With bids fixed at baseline levels, one party, the sellers in the North or the buyers in the South, are left worse off or no better off after the expansion, which allows somewhat greater trade but primarily shifts surplus amongst bidders. Sellers are better off at each level of expansion, by the very fact that they can adjust bids. Buyers are better off with an expansion sufficient to eliminate congestion but would prefer sellers not adjust bids for intermediate levels of transmission expansion in the North.

Welfare increases by much more when sellers adjust their bids to the transmission constraints, as shown by the difference between the thin and thick solid lines in the figure. The ratio of the aggregate welfare gain from both expansions (done independently) with endogenous bids to the gain with fixed bids is 3.55; i.e., the strategic response to the expansions accounts for 72% of their welfare benefit. In aggregate with endogenous bids, the 1200 MW expansions to the North and South regions would have increased welfare by INR 1.39 billion (USD 27.80 million) and INR 4.08 billion (USD 81.67 million), respectively, with the bulk of this gain coming from the competitive response of bidders.

(b) Costs of Infrastructure for Transmission Expansion

The above estimate of social benefits, or increased surplus, from transmission expansion is not comprehensive, as it does not account for the costs of building the needed infrastructure. The socially optimal level of infrastructure investment will generally leave some congestion, for if one built the transmission capacity needed to eliminate every last hour of congestion, there would be no price differences across regions and the marginal benefit of transmission capacity would be zero, below the marginal cost of expansion. To estimate the total change in welfare from transmission expansion I therefore develop a measure of the costs of marginal transmission capacity to compare to the above measure of benefits.

The method of estimating marginal expansion costs has three steps. First, I identify the physical lines that form binding constraints on inter-regional flow during my study period. Second, I use planning documents to ascertain what more would have had to be built to relieve these constraints. Because elements of the grid such as transmission lines and substations are interdependent, the marginal investment required to relieve constraints is above the replacement cost of the constrained grid links. Third, I use regulatory rulings on the costs of existing grid elements to estimate the cost of the marginal expansion proposed. The transmission system is regulated under a cost-plus regulatory regime so the regulator commonly rules on the cost of grid elements similar to those needed for the expansion in the determination of transmission tariffs.

The method of estimating costs can be illustrated with the example of an expansion of the capacity from the East Region to the North Region. The system operator stated, in monthly reports on available transmission capacity, that a transmission link between Farakka and Malda was the constraint on congestion across these regions (Power Grid Corporation of India Limited, 2009). The system operator has developed a plan to circumvent this constraint by building an additional high-voltage line from Rajarhat, near Kolkata, to Purnea along with associated infrastructure (National Load Dispatch Centre, 2012). I take the cost of the planned grid elements from recent regulatory filings for comparable expansions and apply the costs of these elements to the expansion plan (Central Electricity Regulatory Commission, 2012).[25]

Table 6, using this method, summarizes the annualized costs and benefits of marginal, 400 MW expansions in transmission capacity on the East to North and East to South links.[26] The table shows the annual cost of constructing the needed grid elements to expand transmission capacity between regions and the ratio of the gains in market surplus to those costs. I find that marginal transmission expansion on these links would have benefit-cost ratios of 1.63 and 3.50, respectively, both well above one, the break-even level of social returns. These proposed marginal investments have a much higher social return than the 16% private return on equity, i.e. a benefit-cost ratio of 1.16, allowed by the regulator for investment in transmission capacity. Moreover, as the marginal benefits for transmission expansion to the South region, shown in Figure 5, Panel B, flatten out only gradually, additional expansion of this link would also yield benefits exceeding costs by a large amount. Further capacity past 400 MW into the North region, by contrast, would add little to social welfare.[27]

Figure 6 highlights the division of the gains in surplus across importing and exporting regions and the buy and sell sides of the market. In the figure, Panel A shows surplus gains from a 400 MW transmission expansion into the North region and Panel B a like expansion into the South region. In each panel, the three bars grouped on the left represent changes in surplus for buyers (blue), sellers (red) and both sides together (black) in the importing region,

[25] Costs include depreciation, interest and operations and maintenance expenses and are presented on an annual, amortized basis. I exclude the regulated return on equity, which is not a social cost, from cost calculations.

[26] Transmission capacity is typically measured in units of potential (kilovolts); I assume 1 kV line can transmit 1.25 MW of energy to express capacities in energy terms instead.

[27] Holding the marginal cost of expansion constant from 400 MW to 1200 MW of capacity and using the surplus generated by this larger expansion, the ratio of benefits to costs for investments in East-North and East-South are 0.87 and 1.97, respectively. These estimates should be taken with caution as the assumption of constant marginal costs of transmission expansion on these links is likely to be poor. For example, the Farakka-Malda line that constrains East to North region expansion was built at a cost of about INR 16m per 400 kV per year, expanded at a cost of about INR 24m per 400 kV per year, and the planned element in Table 6 is INR 53m on the same basis (Central Electricity Regulatory Commission (2012) Petitions No. 12/2002, 141/2010). The marginal cost curve for transmission investment slopes up as new lines have worse locations, longer runs and more complex tie-ins with the existing grid.

while the three bars on the right represent changes for the exporting region. In the North region, in Panel A, the losses to sellers who lose market power as import capacity grows (red bar, left side) outweigh the gains to buyers from lower prices, so the net surplus change in the region is slightly negative. This loss is offset by large gains to sellers in the exporting regions, which benefit from higher prices and quantity after they are integrated with the high-demand North. The pattern of gains for an import expansion into the South region, in Panel B, is similar, though in this case the gains to buyers within the South (5.2% of baseline surplus) outweigh the losses to sellers from being undercut (2.3%). Thus most of the surplus gains from new transmission accrue in *exporting* regions, whose sellers are able to supply more and at higher prices. Importing regions have modest net gains in surplus because undercutting sellers' market power and hence surplus offsets gains to the buy side from lower prices and greater quantity.

The comparisons above rely on several broad assumptions that, on balance, probably understate the relative benefits of new infrastructure investment. Investment costs are annualized and assumed steady over time.[28] The benefits of the additional capacity, in terms of market surplus, are annualized based on the estimated surplus gains during the rather congested sample period, which may somewhat overstate surplus gains in the short-term. Against this, the benefits of capacity expansion assume no growth in the day-ahead market and, most critically, that additional transmission capacity has no benefit for power markets other than the day-ahead, such as the contract or long-term markets. This last assumption probably significantly understates welfare gains as congestion in the existing transmission grid also affects other markets, though to a lesser extent than the day-ahead market.

8 Conclusion

I study the effect of transmission constraints on welfare in the day-ahead electricity market. Using confidential data on bids, offers and transmission constraints, I estimate bidder costs from a structural model of bidding under transmission constraints. I then simulate the counterfactual gain in welfare from expansions of transmission capacity into constrained regions.

The main finding of the paper is that the welfare gains from transmission expansion are large and mostly due to the competitive effects of additional transmission capacity. Counter-

[28]This assumption typically holds in practice as straight-line depreciation is applied to transmission elements

factual increases of transmission capacity into the congested North and South regions increase market surplus by 19% of its baseline level. By comparison with counterfactuals that hold strategic bids fixed, I calculate that 72% of this welfare gain is due to the transmission expansions decreasing market power. The gains from additional transmission investment exceed their costs. I calculate the costs of transmission investment by applying regulatory rulings on the cost of transmission system elements, which are available under the cost-plus regulation in place for the grid, to grid expansion plans. Expansions into the North and South regions have estimated benefit-cost ratios of 1.63 and 3.50, respectively.

A natural question is why these lines, with positive social returns, have not already been built. Part of the answer is that, given the rapid change in the Indian power sector, it is hard to anticipate the value of infrastructure even a short time into the future. The studied congestion in the day-ahead market would have been especially difficult to foresee as this was a novel power market, the first in India to have publicly available regional prices. In this view the congestion here is a costly but temporary disequilibrium to be remedied as the government continues to expand transmission capacity (Central Electricity Authority, 2012). An additional factor slowing investment may be that lines are built under cost-plus regulation, which reimburses investment based on its cost and not its returns. This incentive structure means that the returns to investment in lines critical for inter-regional trade are no stronger than for any other line, and thus not strong enough.

These findings are based on considering transmission expansion in the day-ahead market in relative isolation and may understate the welfare gains of such investment. Relaxing transmission constraints would likely induce additional buyers and sellers to shift out of the short-term contract market, which is presently favored in the transmission allocation process, and into the day-ahead market, increasing liquidity, lowering transaction costs and bringing trade closer in time to realizations of demand (Mansur and White, 2012). Moreover, there are likely also welfare gains from allocating existing transmission capacity differently across market segments, even without new physical investment. Participants in the long-term and short-term contract markets reserve transmission capacity far in advance of delivery at prices that do not reflect the eventual scarcity of these lines. This is in contrast to other power markets with zonal pricing where the allocation of transmission capacity is done in a uniform manner close to the date of delivery based on willingness-to-pay for energy.

To my knowledge this is the first micro-economic study of a wholesale power market in a developing country. There is an extensive literature on the exercise of market power in deregulated electricity markets around the world and the importance of market design in mitigating market power (Joskow, 2008). Market power is potentially much more important for welfare in developing markets. Market power in mature markets affects production efficiency but not allocative efficiency (Borenstein et al., 2002). When a generator withholds capacity that would be competitive to operate, raising prices, less efficient generators will be called to make up the gap; consumers are served in any case. In India's deficit market, in contrast, power withheld may increase demand not met, from any source, leading to load shedding and large welfare losses. The day-ahead market may be the last chance for a distribution company to procure power rather than cutting customers off.[29] Unreliable, scarce power supply not only harms consumers but also reduces the productivity of firms (Fisher-Vanden et al., 2012).[30]

Electricity markets are especially prone to the exercise of market power, so power transmission infrastructure may be expected to have especially large competitive effects. There is a range of other public infrastructure that may also have competitive effects by promoting arbitrage across space and time. Jensen (2007) is an example of the competitive effects of communication infrastructure. Better transport infrastructure may encourage competition by lowering trade costs directly and expanding access to markets. Public infrastructure for the storage or processing of agricultural goods may have competitive effects dependent on the local market structure for these commodoties. How infrastructure interacts with market structure to determine market outcomes is an important area for future research beyond deregulated electricity markets.

[29] Compare India's average power deficit of ten percent with the one-day-in-ten-years standard for any load shedding of the Northeast Power Coordinating Council (NPCC) in the United States (Central Electricity Authority, 2011a).

[30] The extent of firm investment in captive generation gives some sense of the cost of unreliable power. India has at least an additional 13% of the total capacity of utilities, about 25,000 MW, invested in captive capacity with high marginal costs and low load factors Nag (2010).

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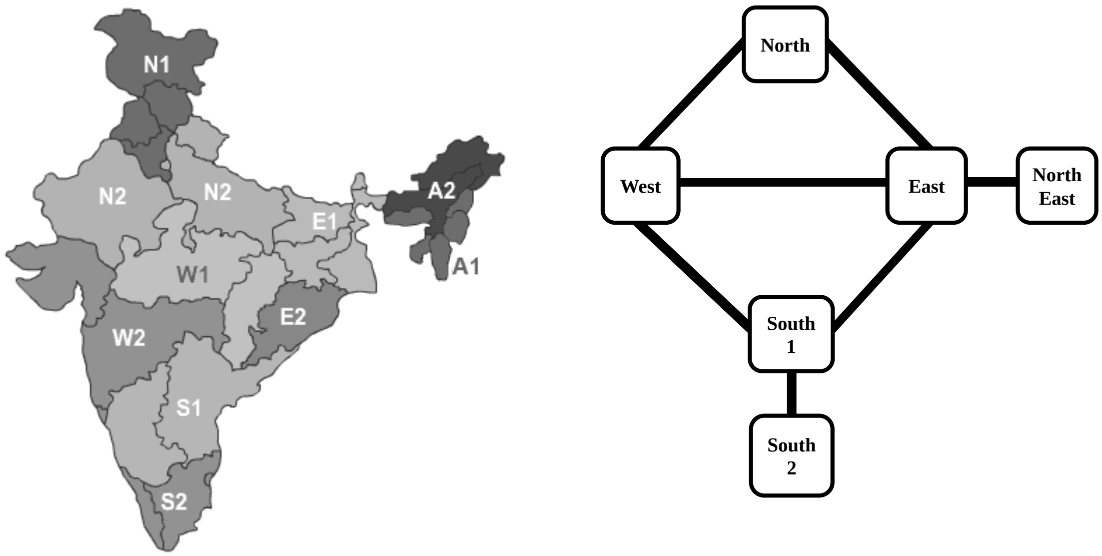
10 Figures

Figure 1: Indian Power Grid

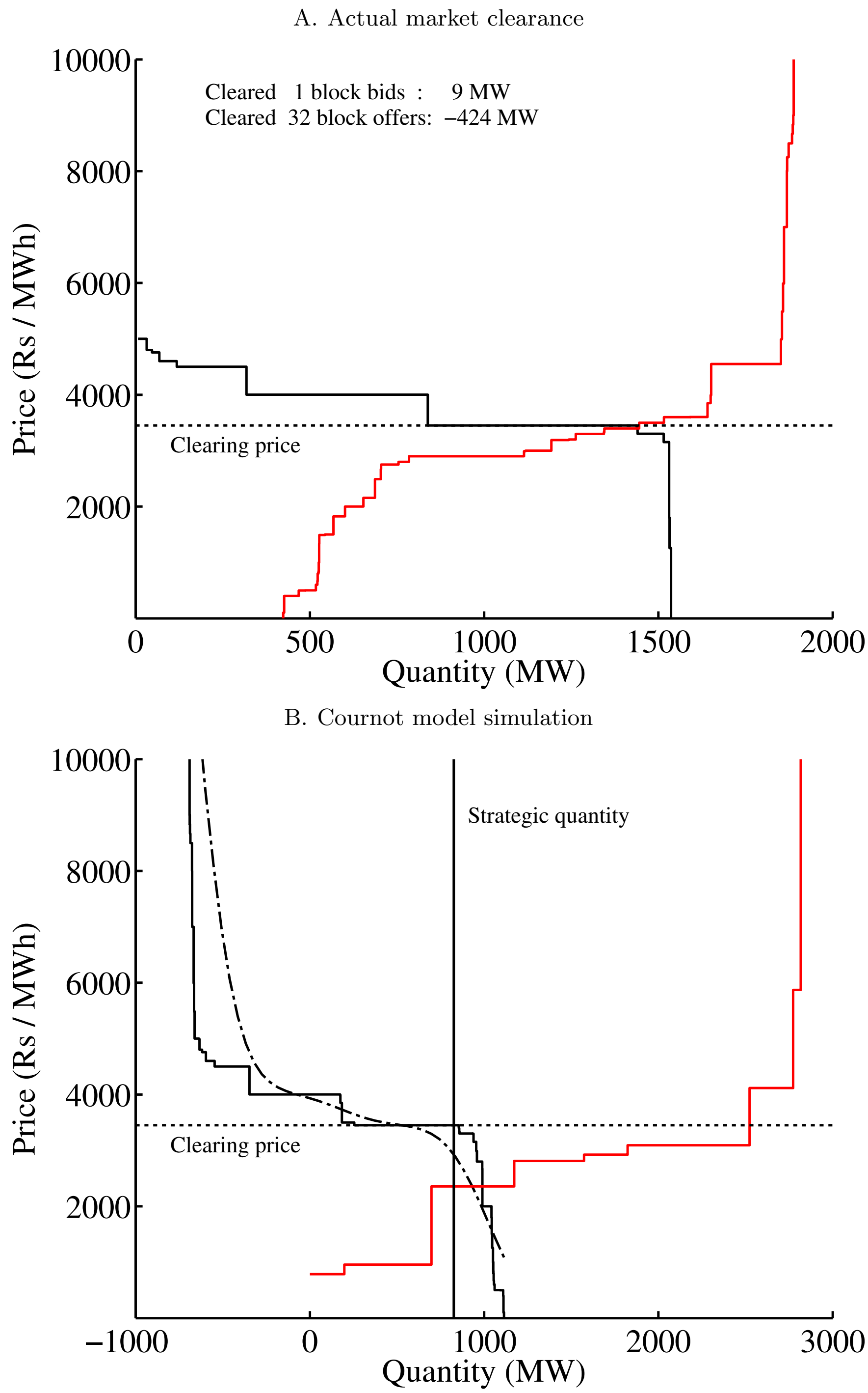
A. Power Exchange Bidding Areas

B. Schematic of Ever-constrained Regions



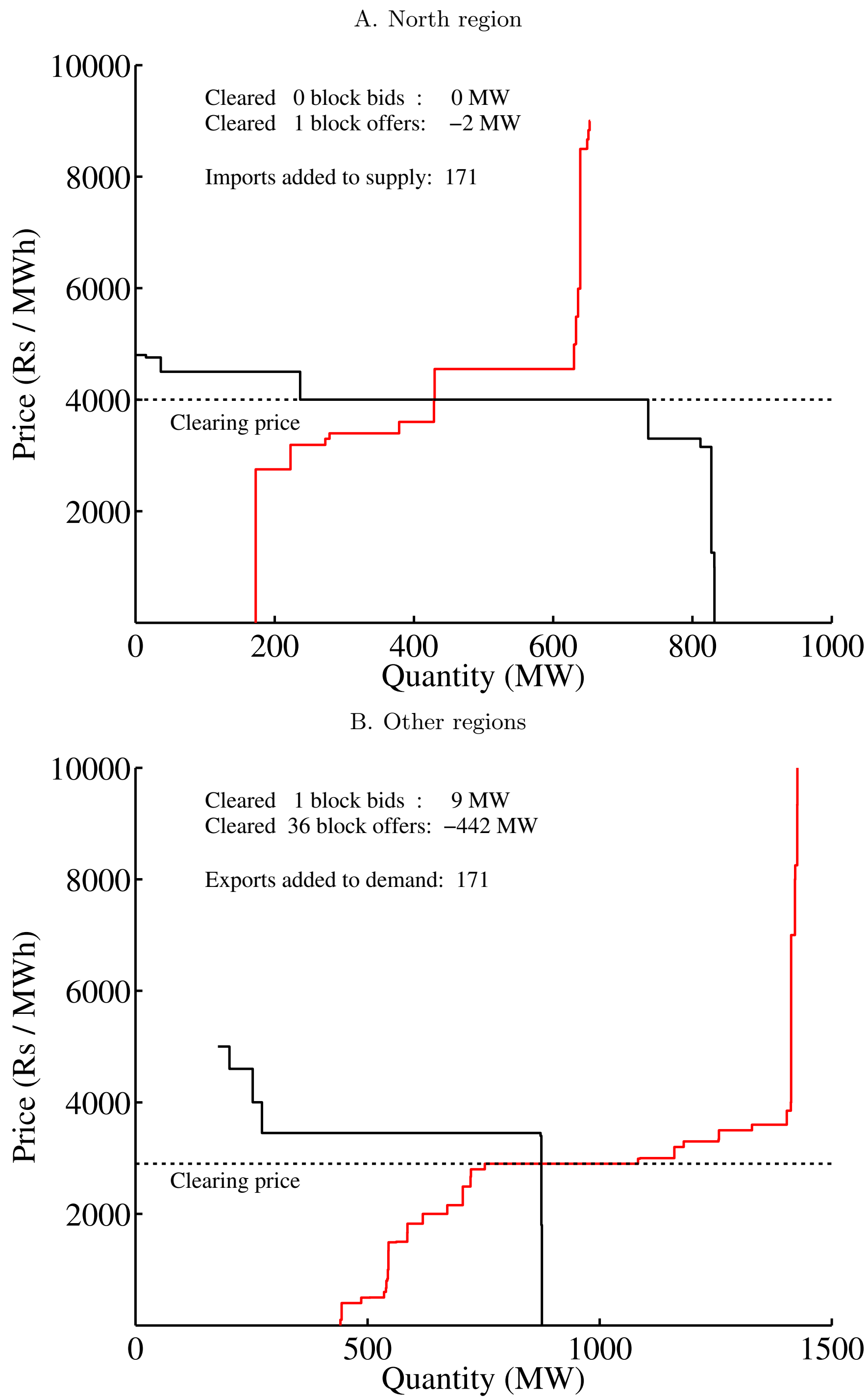
The figure shows geographic and schematic representations of the bidding areas in the Indian day-ahead power market. Panel A represents the ten subregions in which bids are submitted, formed from five regions with two subregions apiece. Panel B represents the six functionally distinct regions that are ever separated by constrained transmission links and the structure of interregional transmission links amongst them.

Figure 2: Unconstrained Market Clearance
January 26th, 2010, hour 17



The figure shows the unconstrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. Panel A shows the actual market-clearing price as determined by the intersection of the downward-sloping demand curve and upward-sloping supply curve, where each curve has been shifted relative to the vertical axis by the volume of cleared buy and sell block bids, respectively. Panel B shows the determination of the simulated market-clearing price. The downward-sloping solid line is the residual demand curve consisting of demand and fringe supply bids and the dashed-and-dotted line a kernel-smoothed representation of this curve. The upward sloping solid line is the aggregate marginal cost curve of the strategic suppliers. The vertical line is the aggregate quantity offered by the strategic suppliers in equilibrium. The equilibrium is determined by the slope of the smoothed residual demand curve but the clearing price, which in this case is the same as the actual clearing price, is determined by the intersection of the strategic quantity with the true residual demand curve.

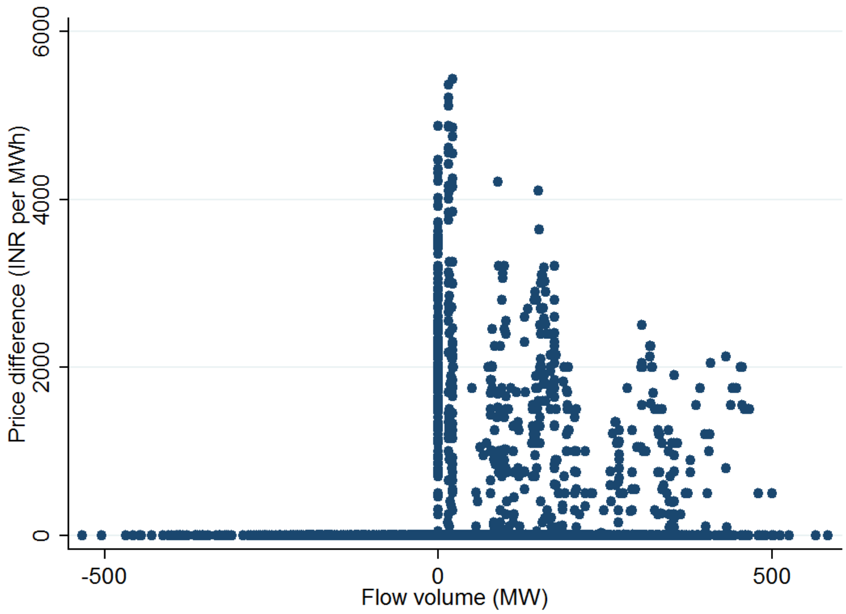
Figure 3: Constrained Market Clearance
January 26th, 2010, hour 17



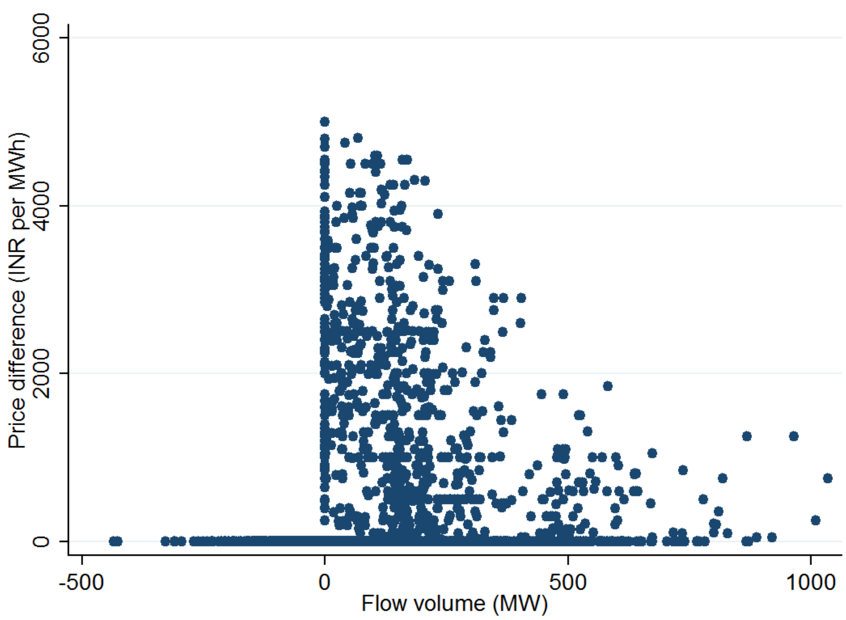
The figure shows the constrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. The unconstrained market clearance shown in Figure 2, Panel A implied a flow of 571 MW to North region when only 171 MW of import capacity was available. The market was therefore split into one import constrained area consisting of the North region, shown in Panel A, and one export constrained area consisting of all other regions, shown in Panel B. The imports and exports have been added to the supply and demand curves in each respective panel.

Figure 4: Regional Price Differences Against Interregional Flows

A. East to North, sample period



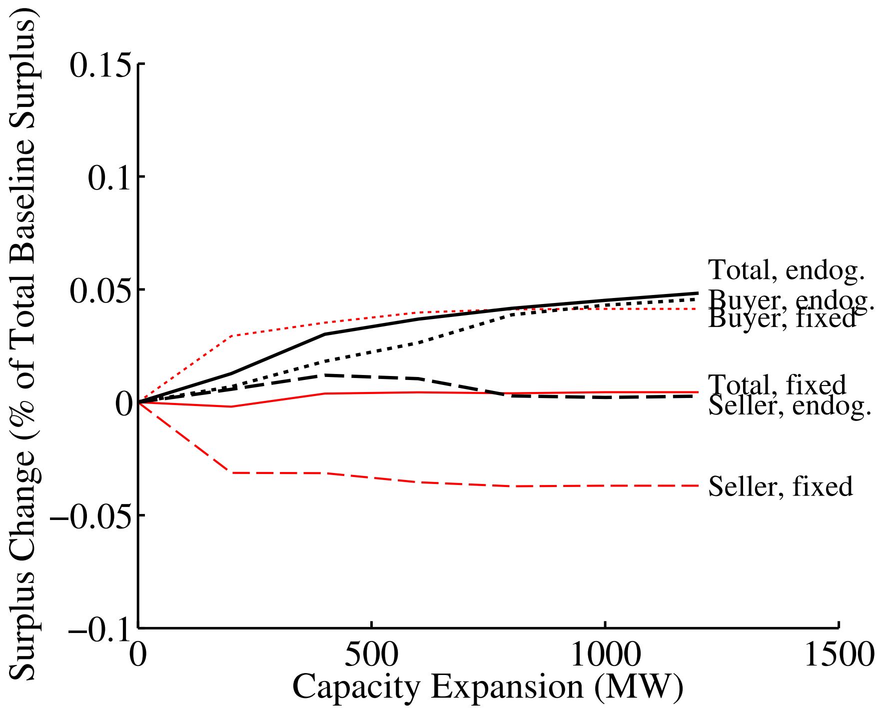
B. East to South, sample period



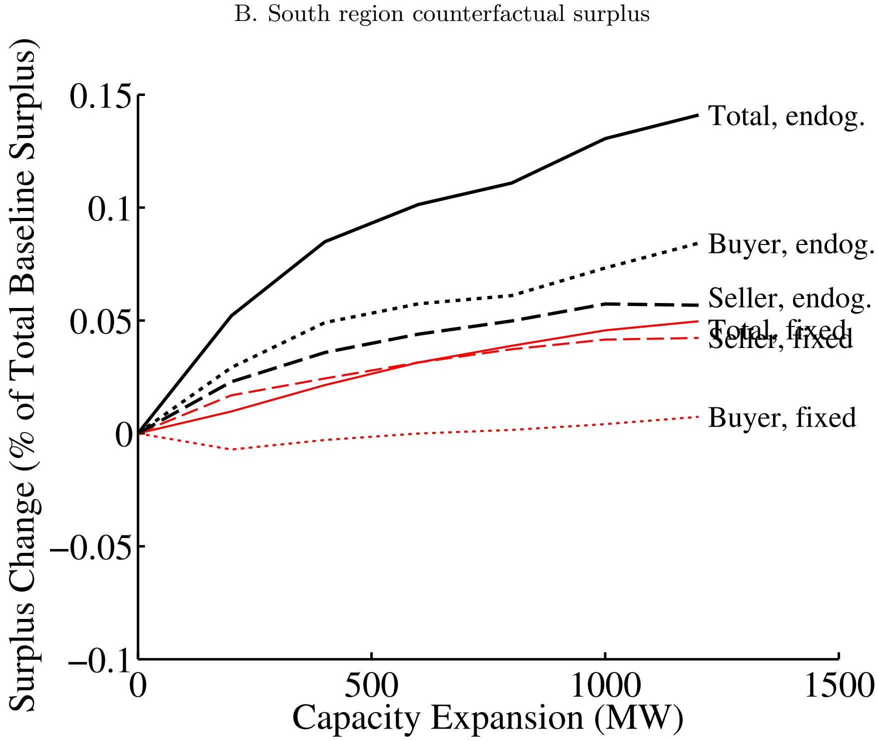
The figure plots the price difference between two regions against the power flow between two regions for the East to North and East to South corridors respectively. The price difference is the South or North price less the East price and the flow the net supply from the East region. A positive price difference implies that the flow is constrained.

Figure 5: Surplus with Relaxed Transmission Constraints

A. North region counterfactual surplus



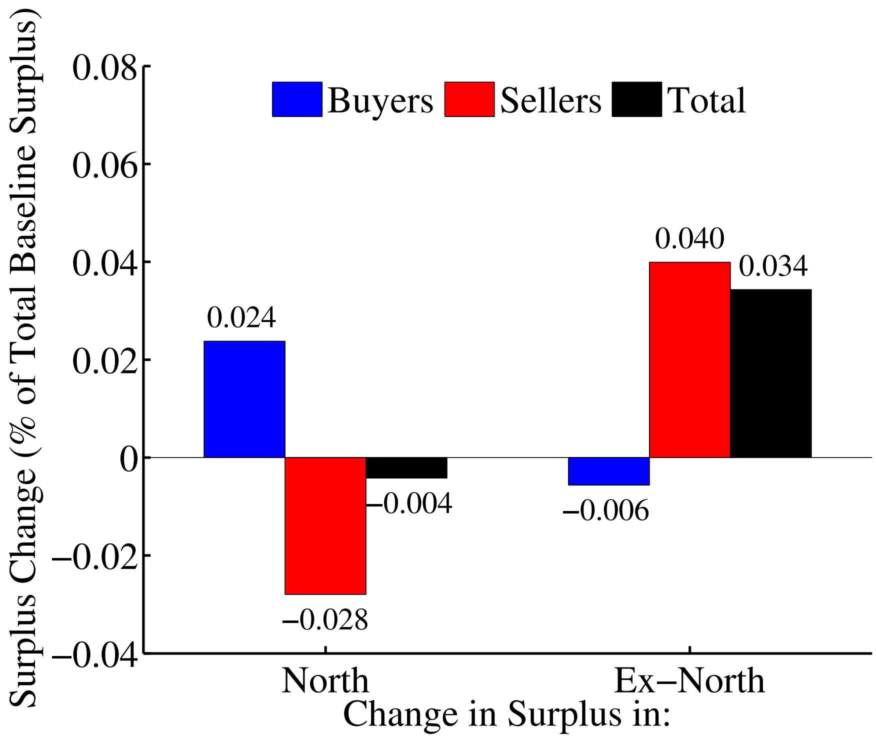
B. South region counterfactual surplus



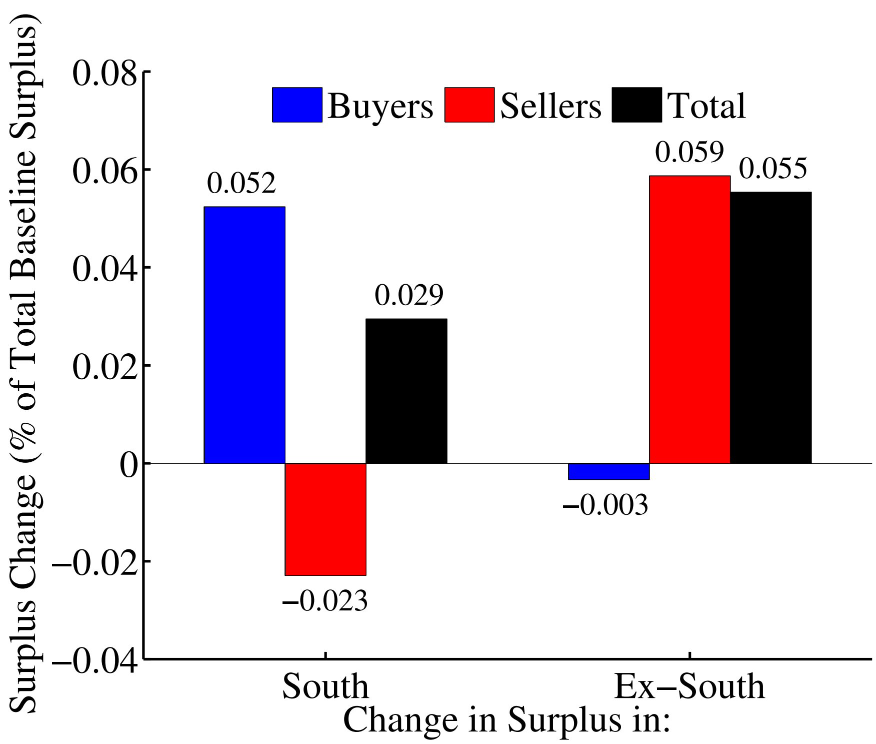
The figure shows changes in surplus for counterfactual increases of transmission capacity. Panel A shows expansions of capacity into the North region and Panel B into the South region. In each panel, the thin (red) lines represent surplus holding strategic bids fixed at the baseline level while the thick (black) lines represent surplus allowing strategic bids to adjust endogenously to the new level of transmission constraints. Within each scenario, the dotted line represents buyer surplus (buyers are more numerous), the dashed line seller surplus and the solid line total surplus. Each surplus measure is scaled by subtracting the baseline surplus for each group and dividing by the total surplus. Each 0.05 share of total surplus represents an annual change of INR 1.41 billion (USD 28 million).

Figure 6: Change Surplus by Region and Market Side

A. North region counterfactual



B. South region counterfactual



The figure shows the division of changes in surplus for counterfactual increases of transmission capacity across regions and sides of the market. Panel A shows expansions of 400 MW capacity into the North region and Panel B into the South region. In each panel, the three bars grouped on the left represent changes in surplus for buyers (blue), sellers (red) and both sides together (black) in the importing region, while the three bars on the right represent changes for the exporting region. Each surplus measure is scaled by subtracting the baseline surplus for each group and dividing by the total surplus. Each 0.05 share of total surplus represents an annual change of INR 1.41 billion (USD 28 million).

11 Tables

Table 1: Market and Bid Summary Statistics

	Mean (1)	Std. Dev. (2)	Min. (3)	Median (4)	Max. (5)	Obs. (6)
Unconstrained price	4352.90	2425.92	99.60	3999.61	13900.55	4344
Number of sell bids	24.70	6.04	12.00	25.00	54.00	4344
Number of buy bids	19.25	8.61	4.00	18.00	48.00	4344
Sell bid ticks	1.84	2.09	1.00	1.00	22.00	107304
Sell bid tick prices	3372.82	2263.49	25.50	3000.00	15000.00	107304
Sell bid tick quantities	33.73	67.47	0.25	9.10	1000.00	107304

Summary statistics for bidding on the Indian Energy Exchange from November, 2009 through April, 2010. Tick quantities are incremental quantities for that tick alone.

Table 2: Prevalence of Congestion

	Northeast (1)	East (2)	North (3)	South 1 (4)	South 2 (5)	West (6)
Panel A: Row Price Higher than Column (%)						
Northeast		0.2	0.2	0.1		0.5
East	0.4					0.3
North	18.5	18.1		17.8	17.4	18.2
South 1	23.5	23.1	23.0			23.3
South 2	26.7	26.3	26.2	7.1		26.4
West	0.4					
Panel B: Row Price less Column Price, Conditional on Being Higher						
Northeast		744.6	384.6	279.9	100.9	618.2
East	5349.7					512.9
North	1768.7	1688.3		1703.6	1732.9	1685.4
South 1	1716.4	1655.5	1652.0			1646.9
South 2	1857.1	1808.5	1806.2	1310.0		1804.4
West	5349.7					

Summary statistics for congestion on the Indian Energy Exchange from November, 2009 through April, 2010. Panel A shows the percentage of hours during this period when the region labeling the row had a price greater than the price of the column region. Panel B shows the row region price less than column region price conditional on the row region price being greater. The mean unconstrained market-clearing price, a point of reference, is INR 4352.90/MWh over the sample period.

Table 3: Strategic Seller Characteristics and Estimated Marginal Costs

Region	Type	Share of Vol. Off. (%)	Maximum Vol. Off. (MW)	Wtd. Mean Tick Price (INR/MWh)	Estimated Marginal Cost (INR/MWh)	Std. Err. (INR/MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
North	State Utility	2.29	700	4667.25	3782.99	(371.75)
North	Discom	7.67	1000	3020.56	2358.99	(89.66)
North	Discom	6.56	500	3669.74	2842.60	(160.14)
North	Discom	1.07	475	4377.05	4132.08	(310.25)
West	State Utility	22.73	400	3659.81	3083.87	(68.72)
West	State Utility	10.90	250	2423.10	1833.15	(54.59)
West	State Utility	2.52	250	4565.90	4035.34	(111.01)
West	Private Genco	8.06	480	1799.12	958.38	(53.61)
West	Private Genco	3.83	65	3342.75	2928.10	(39.48)
West	Industrial Plant	1.46	44	5498.90	3114.95	(142.05)
West	Industrial Plant	1.36	36	6619.72	5942.98	(197.72)
West	Industrial Plant	1.22	250	1828.40	2266.49	(26.12)
West	Industrial Plant	1.03	198	745.06	704.10	(98.30)

Statistics for bidding by strategic sellers on the Indian Energy Exchange from November, 2009 through April, 2010 and estimated marginal costs. Region is the region in which the seller bids, type is the category of bidder to which the seller belongs, share of total volume offered is the share of offered volume offered by each seller, weighted mean tick price is the quantity-weighted average price of bid ticks offered by the seller, estimated marginal costs are the costs recovered via the estimation described in Section 5. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement over both days in the sample and simulated market outcomes. Strategic sellers are those sellers in the North and West region with at least one percent market share as determined by the share of offered volume.

Table 4: Model Fit

	Actual		Model	
	Mean	Std Dev	Mean	Std Dev
	(1)	(2)	(3)	(4)
Unconstrained				
Clearing price (INR/MWh)	4352.90	2425.92	3687.16	1692.78
Clearing quantity (MW)	936.82	328.64	1256.42	525.75
North region				
Clearing price (INR/MWh)	4342.68	2426.17	3803.48	1745.70
Price > West price (% of hrs)	0.18	0.39	0.16	0.37
Price - West Price (if not equal)	1685.38	1091.98	1437.39	984.88
Net demand (MW)	258.45	244.49	323.59	269.22
South 1 region				
Clearing rice (INR/MWh)	4419.46	2559.79	4246.17	2257.18
Price > West price (% of hrs)	0.23	0.42	0.33	0.47
Price - West Price (if not equal)	1646.88	1228.94	2049.47	1291.42
Net demand (MW)	-81.10	180.84	-78.51	186.34
West region				
Price (INR/MWh)	4035.79	2403.17	3664.31	1814.86
Net demand (MW)	-346.12	247.01	-445.20	304.21

The table shows the fit of the constrained Cournot model to market outcomes on the Indian Energy Exchange from November, 2009 through April, 2010.

Table 5: Market Outcomes with Relaxed Transmission Constraints

Expansion relative to baseline	0 MW (1)	400 MW (2)	800 MW (3)	1200 MW (4)
Panel A. North region capacity expansion				
Strategic Bids Fixed at Baseline				
North price > West Price (% of hrs)	0.16	0.02	0.00	0.00
North price - West Price (INR/MWh)	1437.39	1060.98	1908.08	2425.83
North net demand (MW)	323.59	347.90	351.78	351.86
West net demand (MW)	-445.20	-443.51	-445.24	-445.26
Market surplus (INR m / hr)	3.26	3.28	3.28	3.28
Market buyer surplus (INR m / hr)	1.15	1.26	1.28	1.28
Market seller surplus (INR m / hr)	2.12	2.02	2.00	2.00
Strategic Bids Endogenous				
North price > West Price (% of hrs)	0.16	0.07	0.02	0.00
North price - West Price (INR/MWh)	1437.39	1244.06	1148.09	1381.43
North net demand (MW)	323.59	381.03	401.61	407.14
West net demand (MW)	-445.20	-491.19	-509.65	-514.69
Market surplus (INR m / hr)	3.26	3.36	3.40	3.42
Market buyer surplus (INR m / hr)	1.15	1.21	1.27	1.30
Market seller surplus (INR m / hr)	2.12	2.16	2.13	2.13
Panel B. South region capacity expansion				
Strategic Bids Fixed at Baseline				
South 1 price > West Price (% of hrs)	0.33	0.08	0.03	0.00
South 1 price - West Price (INR/MWh)	2049.47	1509.93	1377.20	1734.89
South 1 net demand (MW)	-78.51	-40.65	-22.60	-18.59
West net demand (MW)	-445.20	-448.87	-450.44	-451.00
Market surplus (INR m / hr)	3.26	3.33	3.39	3.43
Market buyer surplus (INR m / hr)	1.15	1.14	1.15	1.17
Market seller surplus (INR m / hr)	2.12	2.20	2.24	2.26
Strategic Bids Endogenous				
South 1 price > West Price (% of hrs)	0.33	0.10	0.06	0.01
South 1 price - West Price (INR/MWh)	2049.47	1652.88	1524.84	1133.65
South 1 net demand (MW)	-78.51	-24.11	10.42	24.40
West net demand (MW)	-445.20	-492.39	-507.59	-512.25
Market surplus (INR m / hr)	3.26	3.54	3.63	3.73
Market buyer surplus (INR m / hr)	1.15	1.31	1.35	1.42
Market seller surplus (INR m / hr)	2.12	2.23	2.28	2.30

The table shows the fit of the constrained Cournot model to market outcomes on the Indian Energy Exchange from November, 2009 through April, 2010.

Table 6: Estimated Cost of Transmission Capacity Expansions into North and South Regions

	Annual Cost/Benefit (INR millions)	Planned Grid Element	Source of Cost Estimate
		Panel A. North region capacity expansion of 400 MW	
Amortized cost	84.75	2 X 500 MVA Substation	Pet. No. 89/2012, Jaipur South
	174.96	2 X 200 kVA Line-in Line-out	Pet. No. 89/2012, Jaipur South
	270.17	450 km 400 kV Line Rajarhat-Purnea	Pet. No. 96/2008, RAPP-Kankroli
	529.88		
Annual surplus	861.98		
Ratio of surplus/cost	1.63		
		Panel B. South region capacity expansion of 400 MW	
Amortized cost	563.97	1600 km HVDC Line and Stations Talcher-Kolar	Pet. No. 84/2005, Talcher-Kolar
	128.81	400 kV DC Talcher-Rourkela	Pet. No. 146/2010, Talcher-Rourkela
	692.77		
Annual surplus	2426.52		
Ratio of surplus/cost	3.50		

The table presents a cost-benefit analysis of new transmission investment to relieve congestion from the East to the North Region and the East to the South Region. The grid elements to be constructed in order to relieve congestion are from National Load Dispatch Centre (2012) and Power Grid Corporation of India Limited (2009). The grid elements to relieve congestion into the North Region are part of an explicit plan from the system operator (NLDC) while the grid elements to relieve congestion into the South Region are inferred from the planning and transmission capacity documents. Cost estimates for each grid element are from granted petitions for cost reimbursement for comparable grid elements filed with the Central Electricity Regulatory Commission (CERC), available at www.cercind.gov.in/orders.html. Cost estimates are on an annual, amortized basis and include depreciation, interest and operations & maintenance costs but not return on equity. The length of the Talcher II-Rourkela link is from the petition cited in the table but the cost of building the line is computed at the higher rate given in Pet. No. 96/2008. All costs are scaled to represent a 400 MW capacity expansion. Annual surplus is the total gain in market surplus each year in the day-ahead market from a 400 MW transmission expansion into each region, calculated by assuming the gain in surplus over the sample period of November, 2009 through April, 2010, as in Table 5, would remain constant.

A Appendix: Institutions

(a) Real-time Balancing through Unscheduled Interchange

The prices for real-time balancing, called unscheduled interchange in the Indian market, depend on the grid frequency, which in turn depends on the balance between demand and supply on the grid. When demand exceeds supply, as is often the case, the grid frequency drops below its nominal frequency of 50 Hz and sellers (buyers) are paid for injecting more (drawing less) power than scheduled. This mechanism takes the place that real-time balancing markets with advance bidding serve in other power systems.

As part of a general effort to prevent buyers and sellers from relying on UI and to improve the balance of demand and supply, which affects grid stability, the relationship between the UI price and the grid frequency has become more steep over time. On April 1st, 2009 the price schedule was increased so that the UI price increased by INR 155/MWh for each 0.02 Hz change in grid frequency and on May 1st, 2010 increased again to INR 215/MWh for each 0.02 Hz change. The net effect of these changes has been to discourage over-demand through UI and push buyers and sellers back, relative to the date of delivery, into the scheduled markets.

There are also regulatory limitations on the use of UI designed to prevent withholding from the scheduled power markets. The UI charges paid to sellers are capped and the maximum allowable deviation from schedule also capped when UI prices are high (Central Electricity Regulatory Commission, 2009) The UI regulation also explicitly threatens sellers that persistently deviate from schedule with regulatory action. Arbitrage at high frequency is further muted by many states apparently settling UI charges over a monthly or quarterly horizon, rather than at hourly prices.[31]

(b) Transmission allocation

The transmission capacity limits determined by the NLDC are allocated among the different segments of the power market in an administrative manner. Long-term customers, which are charged for building and maintaining the transmission grid in proportion to their generation capacity, are given first priority (Central Electricity Regulatory Commission, 2008b). The

[31] Personal communication, S. C. Saxena, National Load Dispatch Centre. This observation is supported by the fact that the correlation of UI and day-ahead prices is higher at the monthly average (0.83) than hourly (0.56) level.

allocation of capacity to long-term trade is nearly constant over time. The margin left after long-term use, due to design margins, short-term variation in power flows and spare transmission capacity due to anticipated future load, is left to short-term trade including both contracts and the day-ahead market (Central Electricity Regulatory Commission, 2008a).

Short-term contractual buyers may book up the corridor that has been reserved for short-term trade on a first-come, first-served basis before the power exchanges. This reservation of the corridor continues until three days prior to the day of delivery, at which time bookings are frozen and the remaining transmission capacity reserved for use by power exchanges. On average more than half of the corridor for short-term use is available for power exchanges, but in some hours short-term contracts exhaust the corridor for all short-term trade.

B Appendix: Market-clearing and Estimation

(a) Discretization of Single Bids

The Indian Energy Exchange allows bids to be piecewise-linear functions from pirce to quantity defined by up to 64 price-quantity pairs. Most bidders use only a small fraction of the available ticks and, moreover, submit bid functions that approximate step correspondences. For example, a seller will submit a bid that is equal to zero up to INR 2499/MWh, that discretely steps up over the minimum allowable INR 1/MWh bidding increment to 50 MW at INR 2500/MWh, and remains constant thereafter.

Table B1 summarizes this behavior for sell bids during the study period of November, 2009 through April, 2010. The percentage of bid segments with any slope is 4.18 for fringe bids and 1.54 for strategic bids. Sloping bid segments do supply a greater quantity than flat segments, at 5.14 and 15.73 percent, respectively, but the share of total quantity offered is still low. Because of the limited use of sloping bid segments, single bids are best represented as discrete step functions. For those bids that do have slope, I approximate sloping segments with discrete steps spaced equally within the price range of the bid segment, at up to INR 250/MWh intervals, such that the average quantity supplied over the segment is the same as in the original bid.

The limited use of bid slope observed may be because the losses to discrete bidding are small and/or the fixed costs of optimal bidding are large (Kastl, 2011; Hortacsu and Puller,

Table B1: Prevalence of Sloping Bid Segments in Sell Bids

	Fringe	Strategic
Bid segment has slope	4.18	1.54
Percentage of quantity with slope	5.14	15.73

2008). The presence of two power exchanges may make the second factor more important in India. The Power Exchange India Limited (PXI) restricts bids to be step functions so bidders may prefer to submit nearly the same bid on both rather than making use of the allowed linearity on the Indian Energy Exchange (IEX).

(b) Treatment of Block Bids

Single bids are hourly functions from price to quantity that are submitted and cleared indepedently for each hour. Block bids specify the maximum willingness-to-pay of a buyer or minimum willingness-to-accept of a seller on average over a continuous block of hours. Each block is specified by a price and quantity p^b, q^b and a set of hours H^b. Blocks allow bidders to reflect cost complementarities in supplying power in contiguous hours, similarly to complex bids (Reguant, 2011). Unlike complex bids, which impose a minimum revenue requirement on the revenues earned by single bids, block bids do not constrain or change the clearance of single bids, other than through their effect on the market-clearing price.

A bidder offering both single and block bids would consider the effect of single bid tick prices on block bid clearance and costs. Let $\hat{p} = \sum_{h \in H^b} p_h / |H^b|$ be the average hourly price over a block and $G(\cdot|H^b)$ be the cumulative distribution function of this price and let δ^b indicate the event that the block is cleared. In terms of equation 1, the bidder's first-order condition for a single bid tick when also bidding with blocks becomes:

$$\begin{aligned}\mathbb{E}_{\sigma_{-it}}\Bigg[\frac{\partial p}{\partial b_{itk}}\Bigg(q_{it}(p) + \frac{\partial D^r_{it}}{\partial p}p + \\ \frac{\partial D^r_{it}}{\partial p}\Big(\delta^b C'(q_{it}(p)+q^b) + (1-\delta^b)C'(q_{it}(p))\Big) + \\ \frac{1}{|H^b|}\Big(q^b + G_{\hat{p}}(p^b|H^b)\Big[C(q_{it}(p)+q^b) - C(q_{it}(p))\Big]\Big)\Bigg)\Bigg]\Bigg|_{p=b_{itk}} &= 0,\end{aligned}$$

The first two revenue terms are the same as in the original condition. The second line is a weighted average of marginal costs over whether a block is included or not, as block clearance shifts a firm along its cost curve. The third line is the change in revenue for the block due to the bid tick changing the average price at which the block is cleared and the non-marginal change in costs from the block being included or not.[32]

Block bids, considered through this modified first-order condition, are not empirically important to the single bids of strategic firms. In the above first-order condition, blocks will matter if block inclusion has a large effect on marginal costs, if the single bid price is likely to change change the distribution of average prices faced by the block and if the block volume is large. None of these conditions hold empirically. Given that marginal costs are assumed constant in the estimation, block inclusion does not shift marginal costs and the second line of this condition reduces to the product of residual demand slope and constant marginal cost. The average block bid submitted by a strategic bidder applies to a block of $|H^b| = 11$ hours, which via line three makes it unlikely that a single bid tick from a single hour will have a noticeable effect on the distribution of block prices. Strategic bidders, moreover, offer only 9.1% of their total offered volume through blocks, summing block volume over all the hours to which a block applies, meaning that the effect of block prices on revenue is then also small as $q^b << q_{it}(p)$. For these reasons I assume in the estimation that strategic bidders do not account for the presence of block bids.

Block bids in aggregate are still an important feature of the market environment and so I replicate the block clearing of the exchange in order to match market outcomes. Auctions with blocks are combinatorial, with the clearance of each block depending on the clearance of the others via market prices, so there is not necessarily a unique set of cleared blocks or cleared market-clearing prices over the day Meeus et al. (2009). The set of blocks cleared will rather depend on the algorithm for block clearance. The precise algorithm of the exchange is not publicly available. I use a heuristic algorithm similar to Reguant (2011) that iteratively drops blocks until a set of hourly market-clearing prices is found:

1. Assume all block bids are cleared.

2. Clear the market for each constrained area in all 24 hours of the day.

3. Calculate the difference between the block price p^b and the average hourly price $\hat{p}$ in the hours to which a block applies, $\Delta p = (1 - 2 \cdot \mathbf{1}\{BuyBlock\})(p^b - \hat{p})$.

[32] I neglect any feedback of the block clearance onto single bids during other hours of the day.

- If $\Delta p > 0$ for any cleared block, designate block with the largest Δp as not cleared and return to (1).
- Otherwise exit.

I do not generally attempt to reinclude blocks that have been dropped at an earlier stage of clearance but may be cleared at the market-clearing prices of later iterations. In step (3) if any block is on the excess side of the market during an hour with an extremal (floor or ceiling) price, that block is given preference to be dropped regardless of whether it has the largest Δp overall. Similarly if at exit the price is extremal in any hour and any blocks on the anti-excess side of the market were not cleared I reinclude such blocks until they are exhausted or the price is no longer extremal.

(c) Market-splitting Algorithm

The algorithm for identifying binding transmission constraints is as follows:

1. Clear the market in the constrained area $\mathcal{A}_g(p|\mathbf{L})$, beginning with the whole market.
2. Calculate regional net demands at the market-clearing price within the constrained area.
3. Calculate constraints from regional net demands
   - Calculate difference between regional net demand and import margin or export margin for each region within the constrained area.
   - Calculate difference between implied interregional flows and total path constraints for each combination of regions within the constrained area.
4. Check constraints
   - If any constraint violated:
     - Update the definition of $\mathcal{A}_g(p|\mathbf{L})$ by partioning the grid on binding constraints.
     - Attribute constrained flows into or out of $\mathcal{A}_g(p|\mathbf{L})$ to appropriate regions.
     - If constraint applies within a previously constrained area relax the outer constraint.
     - Return to (1.) for each constrained area separately.

Table B2: Area-Clearing Price Differences

Quarter	Hours	Unconstrained Clearance Mean Price	Abs Diff	Pct Diff	Hours	Constrained Clearance Mean Price	Abs Diff	Pct Diff
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
200901	2160	6199.33	6.10	0.10	34	6029.18	3.12	0.36
200902	2184	7771.64	14.91	0.19	776	5314.09	41.78	1.44
200903	2208	5326.42	8.13	0.15	1192	4313.33	73.58	2.40
200904	2208	3494.80	3.53	0.10	491	3576.61	108.45	3.78
201001	2160	4108.02	6.38	0.16	1269	4368.14	69.84	2.11
201002	2184	5300.93	7.36	0.14	420	5981.81	50.74	0.91
201003	2208	3067.02	4.22	0.14	174	3293.08	7.60	0.23
201004	2208	2345.78	2.63	0.11	934	2860.87	56.23	1.96
201101	2160	3564.59	1.84	0.05	1695	4848.80	31.61	0.41

- Otherwise exit.

Interregional flows are calculated by minimizing the sum of squared flows subject to meeting the regional net demands (i.e., to Kirchoff's First Law) and respecting binding constraints.

(d) Accuracy of Market Clearing

The replicated block-clearance and market-splitting algorithms are extremely accurate. I test their accuracy by comparing market prices reported by the IEX to those calculated by clearing the market with the bidding data.

Table B2 reports the results of the market clearance for each quarter from the first quarter of 2009 through the first quarter of 2011. The first four columns show the results for unconstrained clearance in all hours, regardless of whether the hour was constrained or not, as the exchange publishes prices for the unconstrained solution in all hours. The percentage difference betwen exchange prices and calculated prices is never more than 0.19 percent of the market clearing price in any single quarter and is more often around 0.10 percent. Columns (5) - (8) show the differences between the mean regional price reported and calculated during constraind hours. The errors are somewhat larger, with a maximum of 3.78 percent of the market clearing price across quarters, but still small on average. The additional error in the constrained relative to the unconstrained price does not necessarily imply error in the market-splitting algorithm. Rather, on inspection, most of the hours when the two prices differ appear to be an interaction of transmission constraints with small changes in block clearance, which affect clearing prices more in relatively illiquid, constrained regions than in the market as a whole.

(e) Accuracy of Bootstrap Replications

The estimation depends on accurately replicating the uncertainty faced by sellers over market-clearing prices and residual demand. This section briefly reports comparisons between the distribution of actual prices and the distribution of prices under the bootstrap replications of market outcomes for the single largest seller.

Table B3: Accuracy of Prices Simulated by Bootstrap

	Unconstrained		North		West	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Mean	4352.90	4369.35	4342.68	4295.72	4035.79	3964.92
Std	2425.92	2422.03	2426.17	2418.23	2403.17	2413.26
Skewness	0.99	0.97	0.97	0.99	1.30	1.29
Kurtosis	3.90	3.95	3.86	4.04	4.54	4.68
Min	99.60	0.00	99.60	0.00	99.60	0.00
p10	1501.70	1502.00	1501.70	1501.00	1500.86	1500.00
p25	2600.47	2601.00	2500.32	2501.00	2499.35	2480.00
p50	3999.61	4000.00	4000.42	4000.00	3400.34	3290.00
p75	5501.51	5751.00	5500.30	5502.00	4999.35	5000.00
p90	8000.52	7950.00	8001.16	7998.00	8000.31	7801.00
Max	13900.55	14768.00	13900.55	18001.00	13900.55	20000.00

Table B3 shows moments of the actual and simulated price distribution for the Unconstrained, North and West prices, respectively. The means and standard deviations of the actual and simulated prices are very similar for each distribution. The simulated prices have slightly fatter tails, with floor prices observed in practice, unlike in the actual prices, and somewhat higher maximum prices. The bootstrap of bids at the daily level does not guarantee there will be demand bids in any given hour, hence generating the floor prices. The other, interior quantiles of the distribution match very closely. The right tails of the Unconstrained distribution, which reflects demand in the South region and the North region, and in the North region, are above the right tails in the West region from the median through the 75th percentile. Comparisons for the uncertainty faced by other sellers and in individual hours of the day also show similar distributions of actual and simulated clearing prices.

(f) Smoothing of Residual Demand

Both the estimation and counterfactual simulations model the residual demand as a smooth curve, rather than a step function. I approximate residual demand and its derivative with kernel-smoothed functions in the manner of Wolak (2007). Let j index bids from both the demand and supply sides, where q_{jk} is the incremental increase in supply or decrease in demand from firm j above price p_{jk}. Let $D^g(0, \sigma_{-it})$ be the total demand in the area of region g at a price of zero and $\mathcal{A}_g$ be short for $\mathcal{A}_g(p|\mathbf{L})$. Then residual demand and its derivative are approximated using a normal kernel as:

$$
\begin{aligned}
\tilde{D}^{rg}_{it}(p|\sigma_{-i}, \mathcal{L}_t) &= D^g(0, \sigma_{-it}) - \sum_{j \neq i, j \in \mathcal{A}_g} \sum_k q_{jk} \Phi\left(\frac{p - p_{jk}}{w}\right) \\
\frac{\partial \tilde{D}^{rg}_{it}(p|\sigma^{\mathbf{s}}{}_{-i}, \mathcal{L}_t)}{\partial p} &= -\frac{1}{w} \sum_{j \neq i, j \in \mathcal{A}_g} \sum_k q_{jk} \phi\left(\frac{p - p_{jk}}{w}\right).
\end{aligned}
$$

The bandwidth w controls the degree of smoothing, with a larger bandwidth smoothing the curve more. I set w = INR 500/MWh in the estimation, which is 11% of the mean unconstrained market-clearing price and 0.21 standard deviations in this price. Own-supply is smoothed in a similar manner. Following Wolak (2007), the derivatives of residual demand and own-supply then form the weights of the first-order condition as $\frac{\partial p}{\partial b_{itk}} = \frac{\partial q_{it}(p)}{\partial b_{itk}} / \left(\frac{\partial D^{rg}_{it}(p)}{\partial p} - \frac{\partial q_{it}(p)}{\partial p}\right)$, by the implicit function theorem.

In Table B4 I test the robustness of the cost estimates to the use of a different smoothing parameter (and to instrumenting the moment conditions with lagged temperature, discussed with the main estimates). Because the smoothing parameter partly determines the elasticity of residual demand, it changes the moment conditions, and one may be concerned that this parameter arbitrarily influences the estimates of marginal cost. In column (4) I present estimates of marginal cost using a smoothing parameter 50% larger than in the baseline case (i.e., w = INR 750/MWh instead of INR 500/MWh). The estimates are practically unchanged, with the mean cost estimate higher by 0.42% and the mean absolute deviation over all cost estimates only 3.42%. The estimated costs thus do not appear very sensitive to a marginal change in the degree of smoothing.

The counterfactual simulation involves strategic sellers maximizing profits with respect to quantity. The conditions for profit maximization therefore depend on the first and second

Table B4: Robustness of Estimated Marginal Costs (INR/MWh)

	IV = No, w = 500		IV = No, w = 750		IV = Yes, w = 500	
Wtd. Mean Tick Price	Estimated Marginal Cost	Std. Err.	Estimated Marginal Cost	Std. Err.	Estimated Marginal Cost	Std. Err.
(1)	(2)	(3)	(4)	(5)	(6)	(7)
4667.25	3782.99	(371.75)	3817.90	(290.46)	4221.06	(346.55)
3020.56	2358.99	(89.66)	2446.98	(96.87)	2873.59	(140.22)
3669.74	2842.60	(160.14)	2879.55	(149.36)	3445.33	(224.46)
4377.05	4132.08	(310.25)	4163.27	(380.11)	5000.33	(380.43)
3659.81	3083.87	(68.72)	3046.16	(79.19)	3216.13	(77.39)
2423.10	1833.15	(54.59)	1829.58	(49.82)	1998.82	(57.20)
4565.90	4035.34	(111.01)	4010.81	(105.71)	4044.78	(101.11)
1799.12	958.38	(53.61)	961.83	(54.12)	1028.98	(65.96)
3342.75	2928.10	(39.48)	2914.22	(46.92)	2983.98	(50.66)
5498.90	3114.95	(142.05)	3366.08	(145.61)	3281.88	(171.45)
6619.72	5942.98	(197.72)	5958.63	(177.82)	6052.60	(196.86)
1828.40	2266.49	(26.12)	2223.22	(26.59)	2252.80	(37.87)
745.06	704.10	(98.30)	526.70	(61.95)	716.10	(105.82)
			Column Means			
3555.18	2921.85		2934.23		3162.30	

Statistics for bidding by strategic sellers on the Indian Energy Exchange from November, 2009 through April, 2010 and estimated marginal costs. Region is the region in which the seller bids, type is the category of bidder to which the seller belongs, share of total volume offered is the share of offered volume offered by each seller, weighted mean tick price is the quantity-weighted average price of bid ticks offered by the seller, estimated marginal costs are the costs recovered via the estimation described in Section 5. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement from the set of moment conditions. Strategic sellers are those sellers in the North and West region with at least one percent market share as determined by the share of offered volume.

derivatives of inverse residual demand with respect to quantity. I represent inverse residual demand as a set of whole quantities and incremental prices and smooth over quantities, in a manner exactly analagous to the above smoothing over prices, in order to approximate the derivative of inverse residual demand. When smoothing over quantity I use a bandwidth w_q equal to ten percent of the range of quantities spanned by the residual demand curve.