The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market

Online Appendix

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This document contains the Online Appendix and supplementary materials for the above-referenced article. There are four lettered appendices. Appendix A gives background on the institutions of the Indian power market and in particular the relationship between different short-term market segments. Appendix B describes the short-term contract market that immediately precedes the day-ahead market. Appendix C describes the market-clearing algorithm in the day-ahead market and the accuracy of my replication of that algorithm. Finally, Appendix D discusses the equilibrium in the counterfactual model and shows robustness checks on the counterfactual results.

A Appendix: Institutions

A.1 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.

The balancing or UI price is a piecewise linear function of grid frequency. 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 steeper over time. On April 1st, 2009 the price schedule was increased so that the UI price increased by USD 3.1/MWh (INR 155/MWh) for each 0.02 Hz change in grid frequency and on May 1st, 2010 increased again to USD 4.3/MWh (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 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 (Central Electricity Regulatory Commission, 2009) The UI regulation also explicitly threatens sellers that persistently deviate from schedule with regulatory action.

A.2 Arbitrage between short-term market segments

Appendix Table A1 shows the correlations between prices across the different short-term market segments at hourly (Panel A) and weekly (Panel B) frequencies. The sample period is 2009 and 2010. The prices are as follows. For the day-ahead market, the unconstrained hourly clearing prices on the Indian Energy Exchange and the Power Exchange India, the two exchanges that make up all trade. For the balancing market, the unscheduled interchange price, calculated by applying the UI Regulations' administered price schedule to the grid frequency. We take the average of the UI price for the Northern-Eastern-Western (NEW) grid and the Southern grid. For contracts, we take the volume-weighted average price of all single-day short-term contracts (signed between 365 and one day in advance of delivery), across all regions of the grid. The timing of the prices is lined up across markets based on the date of delivery of electricity; therefore, because contracts are signed at various times in advance, the contracts may have been agreed up to one year prior to delivery (though most are agreed within a month before delivery).

A.3 Transmission allocation and congestion

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, 2008*b*). The 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, 2008*a*).

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

Table A1: Price Correlations Across Short-term Market Segments

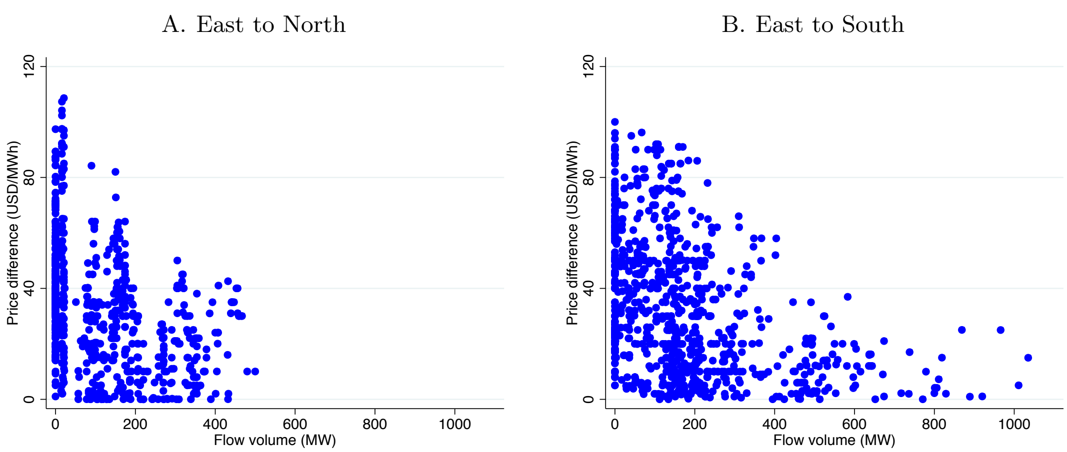
	IEX (1)	PXI (2)	Balancing (3)	Contracts (4)
Panel A. Hourly Frequency				
Day-ahead price, IEX, unconstrained	1			
Day-ahead price, PXI, unconstrained	0.915	1		
Balancing price (unscheduled interchange)	0.598	0.602	1	
Panel B. Weekly Frequency				
Day-ahead price, IEX, unconstrained	1			
Day-ahead price, PXI, unconstrained	0.978	1		
Balancing price (unscheduled interchange)	0.808	0.824	1	
Short-term contract weighted average price	0.714	0.774	0.664	1

The table shows correlations between market prices on various short-term Indian power markets at hourly (Panel A) and weekly (Panel B) frequencies. The prices are as follows. For the day-ahead market, the unconstrained hourly clearing prices on the Indian Energy Exchange and the Power Exchange India, the two exchanges that make up all trade. For the balancing market, the unscheduled interchange price, calculated by applying the UI Regulations' administered price schedule to the grid frequency. The balancing or UI price is a piecewise linear function of grid frequency. We take the average of the UI price for the North, East and Western grids (NEW) and the Southern grid. For contracts, we take the volume-weighted average price of all single-day short-term contracts (signed between 365 and one day in advance of delivery), across all regions of the grid. The sample period is 2009 and 2010.

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, of the corridor that is available for short-term use, more than half is left over for use by the power exchanges. However, in some hours short-term contracts use up all the corridor for short-term trade, in which case power exchanges must solve for market clearance with zero flows between the regions where corridor has been exhausted.

The above transmission allocation process means that, although the amount of physical transmission line does not vary, the amount available for use by the day-ahead market does vary. This variation in available capacity is not exogenous to market conditions, since it depends on how much corridor has been booked up by contract market participants. We may still be interested to see, on this intensive margin, how the severity of transmission constraints is correlated with regional price differences.

Figure A1: Regional Price Differences Against Interregional Flows



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, conditional on a transmission constraint between each pair of regions binding, during the sample period of November, 2009 through April, 2010. The price difference is the South or North price less the East price and the flow the net supply from the East region. A constraint binding implies that the price difference is weakly positive.

Figure A1 charts regional price differences against inter-regional power flows for 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. The panels show only hours when the flow between regions is constrained, causing the constrained areas including each region to be cleared separately and the market-clearing prices in the two regions to differ.[36] As shown in Panel A, power flow being constrained at low levels, below 200 MW, is associated with price differences of USD 100/MWh or above in both regions. These price differences across regions are larger than the average unconstrained clearing price. When more transmission capacity is available, the greater flow between regions eliminates or reduces the price difference, creating the strong negative correlation between price differences and constrained flow in the figure. A similar pattern of price differences decreasing in constrained flow is seen between the South 1 region and the East (Panel B), though a greater flow is needed to close the price gap for this pair.

B Appendix: Contract market

B.1 Contract positions and congestion in the day-ahead market

The analysis uses data from the day-ahead market and assumes that contract positions are exogenous, from the perspective of a firm bidding in the day-ahead market. This section uses data from the short-term contract market to argue that this assumption is reasonable, over a short time horizon, since contracts are not updated in response to congestion at high frequency.

The contract data were obtained from the CERC under a non-disclosure agreement. The data cover all short-term contracts (less than 365 days) for the three fiscal years running from April 1st, 2009 through March 31st, 2012. This period encompasses the sample period used in the analysis of the day-ahead market. The variables include the dates and hours to which the contract applies, the quantity and price and the region of the buyer and seller. The contract

[36] Note that the constraints bind at different levels of flow. The available physical capacity of lines varies a small amount from hour to hour, but there is greater variation in the capacity declared for the day-ahead market due to the booking of corridor for the clearance of prior markets. If a line can support 3500 MW and 3000 MW is booked prior to the day-ahead market, then transmission capacity for the day-ahead market is the residual 500 MW.

data, like the day-ahead bidding data, are anonymized and therefore cannot be linked to the bidding data to learn the contract positions of individual firms.

Most short-term contract volume is traded in contracts that last a month or longer. Table B2 shows the total volume of power traded over this three-year period by the duration of the contract. About 7% of trade is on daily contracts and 81% on contracts of at least 28 days. Since monthly contracts are signed in advance of trade this suggests that the contract positions of firms are largely fixed at high frequencies; a day-ahead bidder would not be changing its contract position much hour-by-hour in response to congestion.

Table B2: Volume of Short-Term Contract Trade by Duration

	Volume (GWh)	Volume (%)
Daily	6086	6.8
Weekly	11309	12.7
Monthly or longer	71897	80.5
Total	89292	

The table shows the volume of short-term contracts by the duration of the contract for all contracts executed through power traders, as reported to CERC. Short-term contracts are by definition less than 365 days. Daily contracts are defined as being for 1 day or less, weekly contracts for more than one day but less than 28 days, and monthly contracts for 28 days or longer.

The estimation strategy assumes that contract positions are fixed and estimates marginal costs as the incremental costs to supply power beyond these contract positions. If contract positions were changing at high frequency in response to day-ahead market conditions, such as congestion, this would imply that the estimated marginal costs would be averaged over different parts of the firm-level cost curve.

To investigate whether contract positions respond to short-term market conditions, here we regress hourly contract volumes, in aggregate, on congestion in the day-ahead market. This test is not definitive: demand for electricity will affect both congestion in the day-ahead market and contract positions in the short-term contract market. Because of this endogeneity, or endogeneity on the supply side, there may be a relationship between congestion and short-term contracts even if firms were not signing contracts in anticipation of future day-ahead congestion. However, there is no clear instrument for congestion in this context, so we present the regression as descriptive evidence.

Table B3 reports the results of this regression. The unit of observation is the hour since

Table B3: Contract Volume by Day-Ahead Congestion

	(1) Volume (MWh)	(2) Volume (MWh)
Congestion in day-ahead market (=1)	-237.5	-36.9
	(141.0)	(86.0)
Month-of-year controls	No	Yes
Mean volume (MWh)	3578.85	3578.85
Observations	23909	23909

The table reports regressions of hourly contract volume on day-ahead market transmission congestion. The data set consists of all short-term contracts from electricity traders over the period from April, 2009 through March, 2012. Standard errors are clustered at the month level to account for the persistence of contract positions. The symbol * denotes $p < 0.05$, ** $p < 0.01$ and *** $p < 0.001$.

this is the time block for clearance of the day-ahead market. In column (1) the regression estimate with no controls is that congestion in an hour is associated with contract volume for that hour being lower by 237.5 MWh (standard error 141.0 MWh), which is statistically insignificant, on a mean contract volume of about 3600 MWh. This correlation may be related to seasonal patterns of demand and congestion. In column (2) we add month-of-year dummies as control variables and the coefficient decreases in magnitude to -39.6 MWh (standard error 86.0 MWh). This estimate is small, at about one percent of overall contract volume, and statistically insignificant.

We can also test whether prices in the contract market anticipate the congestion that will arise in the day-ahead market. Table B4 regresses the differences in volume-weighted contract prices across regions, for a given day and hour of trade, on whether or not those regions will end up being congested in the day-ahead market. The dependent variable is therefore the gap in regional prices, shown separately for the most important two pairs of regions: the North region price less the West region price (columns 1 and 2), and the South region price less the West region price (columns 3 and 4). The independent variable of interest is whether or not the North (or South) region is congested from the rest of the grid in a given hour.

The Table B4 regressions find small effects of future congestion on gaps in contract prices. In the North region, contracts are priced on average INR 0.088 per kWh (standard error 0.037) higher when the day-ahead market will be congested, relative to West region contracts, as compared to a mean West region contract price of INR 4.04 per kWh. The gap in prices due to anticipated congestion is therefore 2% of the mean price. For the South less West

Table B4: Regional Differences in Contract Prices by Day-Ahead Congestion

	Dependent variable: Contract price gap			
Gap between regions:	North less west		South less west	
	OLS	OLS	OLS	OLS
	(1)	(2)	(3)	(4)
North region congested (=1)	-0.29	0.088		
	(0.070)	(0.037)		
South region congestion (=1)			0.64	0.021
			(0.080)	(0.036)
Date effects		Yes		Yes
Hour quartic		Yes		Yes
Mean West region price (Rs/kWh)	4.04	4.04	4.04	4.04
Observations	4344	4344	4344	4344

The table shows regressions of gaps in contract prices between regions on whether or not the day-ahead market is congested. Since contracts are signed before the day-ahead market clears, the congestion status is not known at the time of contract trade; therefore the regressions are tests of the extent to which contract prices anticipate day-ahead market congestion. The dependent variable is the difference in mean prices in a given hour between contracts with sellers in two different regions. The independent variable of interest is a dummy for whether the day-ahead market would, when it later cleared, be congested in that hour. Robust standard errors clustered by date are in parentheses.

region price gap, the estimated coefficient on realized South region congestion is even smaller and not significantly different from zero (coefficient INR 0.021 per kWh with standard error 0.036). The results of this table confirm the results suggested by the volume regressions: contract prices do not anticipate congestion to any meaningful extent.

The relationship between the contract market and congestion in the day-ahead market is therefore a bit of a puzzle. Prices in the two markets are highly correlated, as we would expect due to arbitrage across segments (Table A1). Yet, contract volumes (Table B3) and prices (B4) do not anticipate congestion in the day-ahead market to a large extent.

One interpretation of this apparent puzzle is that contracts anticipate market conditions in the aggregate but sellers do not anticipate the pattern of congestion, at high frequency, far in advance. To provide evidence on this idea Table B5 measures the stability of short-term contracted volumes by seller. The rows of the table show summary statistics for sellers in the four quartiles of the distribution of seller volume, and in total across all sellers. The columns of the table show summary statistics across time periods, either across the days within a month (columns 1 through 3) or across the hours within a day (columns 4 through 6). Therefore, for example, the first row entry in column 2, 4.17 MWh, gives the standard

Table B5: Stability of Contracted Quantities

Contract size quartile	Across days within month			Across hours within day		
	Mean (MWh) (1)	Standard deviation (MWh) (2)	Coefficient of variation (3)	Mean (MWh) (4)	Standard deviation (MWh) (5)	Coefficient of variation (6)
Quartile 1						
Mean	75.01	4.17	0.05	3.88	0.00	0.00
Median	76.97	0.00	0.00	4.18	0.00	0.00
Quartile 2						
Mean	193.63	11.49	0.06	9.56	0.13	0.01
Median	194.57	0.00	0.00	9.66	0.00	0.00
Quartile 3						
Mean	400.43	41.92	0.10	21.77	0.64	0.03
Median	375.00	0.00	0.00	18.31	0.00	0.00
Quartile 4						
Mean	3114.43	346.14	0.11	154.31	16.06	0.10
Median	2015.04	59.51	0.05	113.46	0.00	0.00
Total						
Mean	945.87	100.86	0.08	46.99	4.17	0.03
Median	270.15	0.00	0.00	12.68	0.00	0.00

The table shows summary statistics on the variation of contracted quantities within a seller over the course of a month or a day. The row sections show summary statistics for sellers in the four quartiles of the distribution of seller volume. Within each row section the two rows show the mean and median, across sellers, of a given column statistic. The column statistics are the mean, standard deviation and coefficient of variation of contracted quantities across seller-days within a seller-month, in columns 1 through 3, and across seller-hours wtihin a seller-day, in columns 4 through 6. The sample for columns 4 through 6 is restricted to sellers that have some contracted volume in all hours of the day.

deviation of contract volume across days within a month, for contracts in the first quartile of volume. The table aggregates contracts to the seller level because sellers may, in principle, have multiple contracts that apply to the same time period: for example, a baseload contract for all hours of the day, and separate contract to supply power during peak hours at a higher price.

The main finding of the table is a remarkable stability in contract volume both across days within a month and across hours within a day. For example, the median (mean) seller contract volume across days within a month is 270 (946) (column 1, bottom rows), with median (mean) coefficients of variation of 0 (0.08) (column 3, bottom rows). Contract volume barely changes across days. Even for the fourth quartile of volume, the largest sellers, the coefficient of variation in volume has an average of 0.11 and a median of 0.05. Most sellers contract for a single quantity and do not change it day to day. Similarly, the coefficient of variation in contracted volume across hours with a day has an average of 0.03 and a median of 0 (column 6, bottom rows).

The stability of contracts shown here supports the assumption in the paper that contract volumes can be taken as fixed in the short- to medium-term. The cost estimates assume that each seller has a single marginal cost. That assumption is motivated in part by the fact that sellers seldom bid multiple price ticks. A possible concern with this cost structure is that sellers in the day-ahead market may have a single cost in any given hour, but may shift up and down their cost curve across hours, due to changes in contract position, and therefore have widely varying marginal costs over time. The fact that contract volumes are so stable suggests that the shifts along a cost curve caused by changes in contract volumes would be small.

Over the medium- and longer-term, such as in response to a permanent expansion of the transmission grid, we expect contract positions would change. The implications of these changes for counterfactuals are discussed in Section VI.

Finally, for this subsection, I consider the predictability of congestion at shorter time horizons. Given the results above about the weak relationship between day-ahead congestion and contract outcomes, for short-term contracts, one may wonder how much bidders in the day-ahead market are able to anticipate congestion. The cost estimates do not assume prefect foresight but rather that bidders form expectations of congestion based on market conditions (bootstrapped from bids around the same time). Short-term contracts are signed at least 3 days before delivery up to 365 days before, whereas the day-ahead market clears 1 day before delivery, so there may be differences in the predictability of congestion across these market segments.

Table B6 shows the preditability of congestion at short frequencies. The dependent variable is a dummy for whether the North region is congested from the rest of the grid. The independent variable of interest is a dummy for whether the North region was congested in the previous day's market clearance (all columns).

I find that congestion is highly predictable at short time horizons with even very simple models. The coefficient on lagged North region congestion is 0.83 (standard error 0.026) and a regression with only one lag and a constant has an R^2 of 0.69. In column 2 I add additional lags

Table B6: Predictability of Congestion

	Dep. var.: North congested (=1)		
	OLS (1)	OLS (2)	OLS (3)
North region congested, 24-hour lag (=1)	0.83 (0.026)	0.47 (0.061)	0.40 (0.062)
Additional lags		Yes	Yes
Lagged prices			Yes
R^2	0.69	0.72	0.73
Observations	4344	4344	4344

The table shows regressions of a dummy for congestion in the North region on lagged congestion and other lagged variables, to understand to what extent congestion is predictable. Column 1 includes only congestion lagged by 24 hours and a constant. Columns 2 and 3 add additional lagged congestion dummies and additional lagged prices. All explanatory variables are observable at the time of bidding. Robust standard errors clustered by date are in parentheses.

of congestion and in column 3 lagged prices, which may have information about the intensity of congestion. These additions increase the R^2 somewhat, to 0.73. Bidders may use much more sophisticated models in order to forecast congestion. Therefore, despite that contracts do not appear to anticipate congestion at medium-term time horizons, it is reasonable to assume that bidders in the day-ahead market can anticipate congestion well enough that expected congestion may change their bids.

B.2 Robustness of reduced-form bidding results

This subsection considers the robustness of the Table 4 estimates of the effect of congestion on bidding to changes in the specification. Table B7 shows specifications related to those of Table 4, regressing prices bid by sellers in the North region on congestion. (See Section II.D of the paper for a discussion of the variables and sample.)

The OLS estimates of the effect of congestion on bidding are stable across specifications. Columns 1 through 4 show OLS estimates of the effect of bidding under different specifications. The coefficient in column 1 shows that prices bid are 7.86 USD per MWh higher in congested hours, relative to a mean of 95.56 USD per MWh in the sample as a whole (including both congested and uncongested hours), conditional on month fixed effects, a quartic polynomial in hour of day and dummy variables for each decile of temperature, an important determinant

Table B7: Offered Prices and Grid Congestion for North Region Suppliers

Dependent variable:	Price bid							
	OLS (1)	OLS (2)	OLS (3)	OLS (4)	IV (5)	IV (6)	IV (7)	IV (8)
North region congested (=1)	7.86 (1.07)	6.87 (0.74)	6.47 (0.63)	6.12 (0.62)	8.63 (2.18)	6.06 (2.95)	12.9 (2.57)	13.6 (2.37)
Price (INR/kWh)				0.82 (1.48)		0.82 (1.56)		
Volume (MWh)				0.0016 (0.00056)		0.0016 (0.00070)		
Month effects	Yes	Yes						
Date effects		Yes	Yes	Yes	Yes	Yes	Yes	Yes
Hour quartic	Yes	Yes	Yes	Yes	Yes	Yes		
Hour effects							Yes	Yes
Temperature deciles	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bidder effects		Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bidder × month effects		Yes						
Bidder × quantity			Yes	Yes	Yes	Yes	Yes	Yes
Bidder × hour								Yes
Mean in uncongested hours	95.56	95.56	95.56	95.56	106.37	95.56	106.37	106.37
Observations	141455	141455	141455	141455	141455	141455	141455	141455

The table shows regressions of bid prices on congestion with observations at the bid-tick level. The sample consists of all supply offers within the North Region for hourly auctions in the period from November, 2009 through April, 2010. The dependent variable is the price of a bid tick in USD per MWh. Observations are weighted by tick quantity so that the coefficients represent the change in the average price of a MWh bid. The explanatory variable of interest is whether the North Region is import constrained in a given hour. The control variables in various specifications include month and date effects, a quartic polynomial in hour of day, dummy variables for deciles of the temperature distribution in the North Region, bidder fixed effects, and bidder-specific linear and quadratic terms in the offered quantity of a bid. Columns 1 through 4 are estimated by ordinary least squares. Columns 5 onward are estimated by two-stage least squares where the instrument for congestion is the transmission capacity available for short-term open access imports into the North Region in MW. Column 7 replaces the quartic polynomial in hour of day with hour of day fixed effects. Robust standard errors clustered by date are in parentheses.

of demand. Column 2 moves from month to date fixed effects and column 3 further adds bidder fixed effects and separate quadratic controls for quantity offered by each bidder. The coefficients with both sets of finer controls are similar to that in column 1. In the column 3 specification, adding bidder fixed effects, the same bidders bid prices 6.47 USD per MWh (standard error 0.63) higher in congested hours than they bid in uncongested hours for the same quantity.

Prices bid are endogenous to demand and supply conditions in the day-ahead market as well as possibly to positions in the contract market. There are two channels for this endogeneity. First, it may be that unobserved shocks, such as shocks to cost, both increase day-ahead price offers and make it more likely that the grid is congested. An example of such a shock would be the outage of a low-cost generating unit in the North Region. Second, changing contract positions may affect the position of a supplier on their supply curve, and therefore the marginal cost of generation. For example, if sellers have already sold most of their power in contract markets, they may have to sell higher-cost supply into the day-ahead market, which would raise prices bid.

To address this endogeneity concern, I take two complementary approaches: controlling for contract market conditions and instrumenting for congestion. Column 4 regresses bid prices on congestion controlling for contract market prices and volume. I find that greater contract market volume does predict congestion, consistent with the institutional feature that the contract market may use up transmission capacity that would otherwise be used by day-ahead bidders. However, the effect of congestion on bidding remains large and significant with this control, and I cannot reject that the column 4 estimate, with controls for contract market conditions, is equal to the column 3 estimate, without these additional controls.

Table B7, columns 5 through 8 instrument for congestion. The instrument for congestion is the availability of transmission capacity, short-term open access (STOA). The IV estimate of the coefficient on congestion, USD 8.63 per MWh (standard error 2.18) is somewhat larger than, but not statistically different from, the OLS estimate in column 5. Column 6 adds controls for contract market price and volume to the IV specification, so that the instrument is variation in the availability of transmission capacity, conditional on overall contract price and volume. As in the OLS specifications, the point estimate of the effect of congestion on prices offered (column 6) is slightly smaller than without these controls (column 5), but remains large and significant. I cannot reject that the coefficient in the IV model with added controls for contract market conditions (column 6) is equal to either the OLS coefficient (column 4) or the IV coefficient without the added controls (column 5).

Finally, Table B7, column 7 replaces the hour of day polynomial with hour fixed effects and column 8 interacts these hour fixed effects with bidder fixed effects. These specifications therefore control flexibly for bidders that may persistently offer higher bids at certain times of day, regardless of congestion, which would bias IV estimates if such persistent offers are correlated with the availability of transmission corridor. We retain controls for bidder-specific quantity offered. In these specifications, the estimated effects of congestion on bidding are somewhat larger than the main estimates, though not significantly so. For example, the column 7 estimate is that congestion increases prices bid by USD 12.9 per MWh (standard error USD 2.57 per MWh), to be compared to the main estimate of USD 8.63 per MWh (standard error USD 2.18 per MWh).

I therefore conclude that the finding that the prices bid by strategic sellers respond to congestion is robust to specification checks that address the most likely sources of congestion endogeneity.

C Appendix: Market-clearing and Estimation

C.1 Discretization of Single Bids

The Indian Energy Exchange allows bids to be piecewise-linear functions from price 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, using the original currency in which bids are submitted, 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 C8 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 USD 5/MWh intervals, such that the average quantity supplied over the segment is the same as in the original bid.

Table C8: 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

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, 2012; Hortaçsu and Puller, 2008).

C.2 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, 2014). 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 2, the bidder's first-order condition for a single bid tick when also bidding with blocks becomes:

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

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.[37]

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 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 percent

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

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 are still a 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, Verhaegen and Belmans, 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 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, $\Delta p = (1 - 2 \cdot \mathbf{1}\{BuyBlock\})(p^b - \hat{p})$.
    - 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.3 Market-splitting Algorithm

The exact algorithm used by the exchange is not published. I recreate the algorithm here and show in the next section that my recreation matches published area-clearing prices very well. The algorithm runs 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.
   - If any exporting area has a higher price than an area to which it is exporting
     - Join the two areas
   - Otherwise exit.

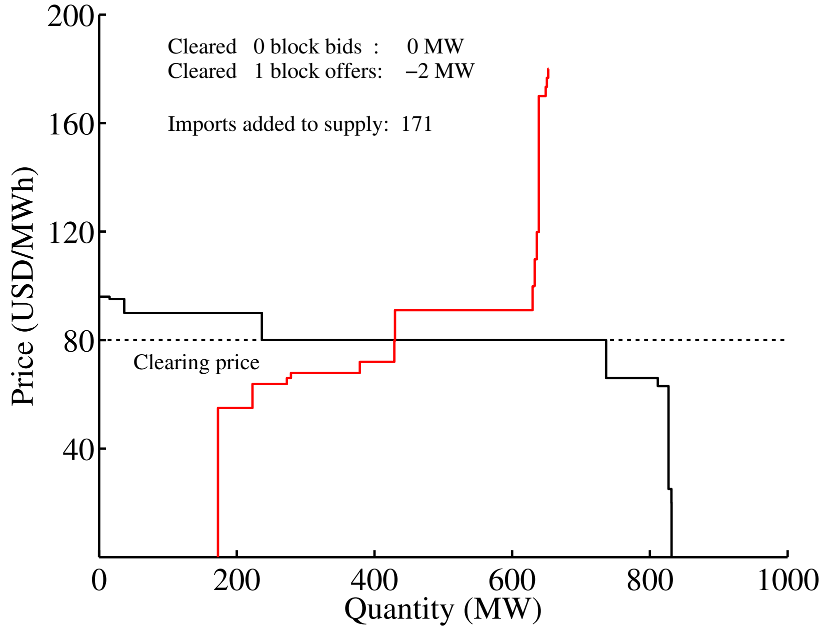
Interregional flows are calculated by minimizing the sum of squared flows subject to meeting the regional net demands (i.e., to Kirchoff's First Law) and respecting binding constraints.

Figure C2 shows the application of the market-splitting algorithm in practice. 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 C2, 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 USD 20/MWh above the other regions and no further constraints bind once these areas are cleared separately. Bidders in each constrained area receive the area-clearing price in that area.[38]

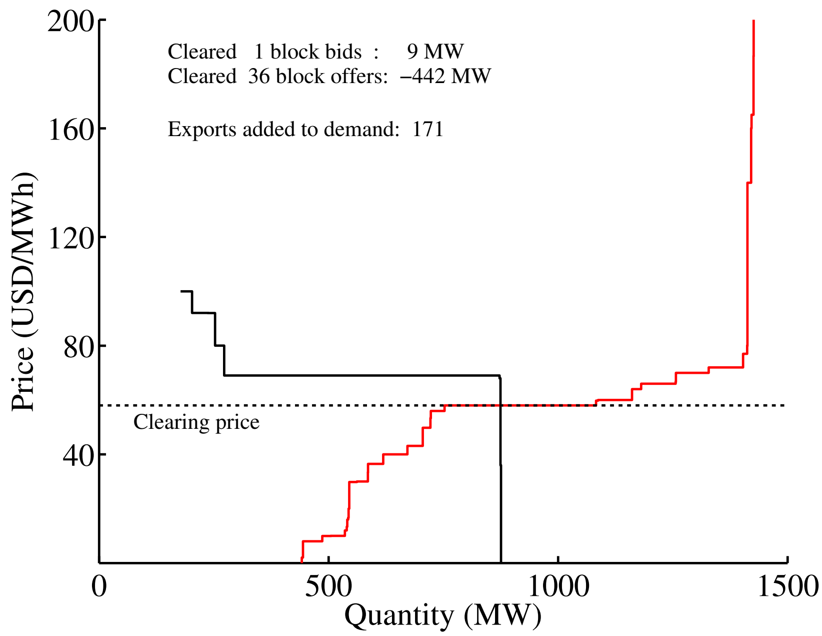
[38] The difference between selling prices in exporting regions and buying prices in importing regions is retained by the system operator, under supervision of the regulator, in a Power System Development Fund. As of March 31, 2011 this fund held USD 91 million (INR 4.57 billion) in congestion revenues.

Figure C2: Constrained Market Clearance
January 26th, 2010, hour 17

A. North region



B. Other regions



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.

Table C9: Area-Clearing Price Differences

Quarter		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	123.99	0.12	0.10	34	120.58	0.06	0.36
200902	2184	155.43	0.30	0.19	776	106.28	0.84	1.44
200903	2208	106.53	0.16	0.15	1192	86.27	1.47	2.40
200904	2208	69.90	0.07	0.10	491	71.53	2.17	3.78
201001	2160	82.16	0.13	0.16	1269	87.36	1.40	2.11
201002	2184	106.02	0.15	0.14	420	119.64	1.01	0.91
201003	2208	61.34	0.08	0.14	174	65.86	0.15	0.23
201004	2208	46.92	0.05	0.11	934	57.22	1.12	1.96
201101	2160	71.29	0.04	0.05	1695	96.98	0.63	0.41

C.4 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 C9 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, all in USD/MWh, 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 very 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.

C.5 Day-ahead bidding with forward contract position

This section slightly extends the firm's problem from Section III by including forward physical contract positions. Exogenous physical contract positions only affect the firm's problem by moving the firm along its cost curve.

The firm's problem is:

$$max_{\mathbf{b_{it}},\mathbf{q_{it}}} \mathbb{E}_{\sigma_{-it}} \left[q_{it}^{DA}(p^{DA})p^{DA} + q_{it}^{C} p_{it}^{C} - \tilde{C}_i(q_{it}^{DA}(p) + q_{it}^{C}) \right].$$

where $\mathbf{b_{it}}$ and $\mathbf{q_{it}}$ are vectors of bid tick prices and quantities. The supply function $q_{it}^{DA}(p^{DA})$ is the supply function in the day-ahead market, which depends on the price b_{itk}^{DA} and the cumulative quantities q_{itk}^{DA} of all bid ticks k offered at an equal or lesser price. The total cost of production is $\tilde{C}_i(\cdot)$. The contract quantity q_{it}^{C} and price p_{it}^{C} are taken as exogenous.

We consider a grid without congestion to simplify notation. Taking the derivative with respect to each bid-tick price, a necessary first-order condition for profit maximization is

$$\mathbb{E}_{\sigma_{-it}} \left[\frac{\partial p^{DA}}{\partial b_{itk}} \left(q_{it}^{DA}(p^{DA}) + \frac{\partial D_{it}^{rg}(p^{DA}|\sigma_{-it})}{\partial p^{DA}} (p^{DA} - \tilde{C}_i'(q_{it}^{DA}(p) + q_{it}^{C})) \right) \right] \Bigg|_{p^{DA}=b_{itk}} = 0.$$

The contract price and quantity are irrelevant for the revenue part of this condition since the contracting decision is sunk. The contract quantity affects bidding through the cost function since firms that have contracted now have to produce with higher-cost units, further out on the marginal cost curve. If we define $C_i'(q_{it}^{DA}(p)) = C_i'(q_{it}^{DA}(p)|q_{it}^{C}) \equiv \tilde{C}_i'(q_{it}^{DA}(p) + q_{it}^{C})$, then the first-order condition here is the same as in the text. Thus from ignoring physical contract positions the only affect on bidding, and hence estimation, is that marginal costs must be interpreted as incremental costs beyond firms' (unobserved) forward contract positions.

C.6 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 C10 shows moments of the actual and simulated price distribution for the Uncon-

Table C10: Accuracy of Prices Simulated by Bootstrap (USD/MWh)

	Unconstrained		North		West	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Mean	87.06	87.39	86.85	85.91	80.72	79.30
Std	48.52	48.44	48.52	48.36	48.06	48.27
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	1.99	0.00	1.99	0.00	1.99	0.00
p10	30.03	30.04	30.03	30.02	30.02	30.00
p25	52.01	52.02	50.01	50.02	49.99	49.60
p50	79.99	80.00	80.01	80.00	68.01	65.80
p75	110.03	115.02	110.01	110.04	99.99	100.00
p90	160.01	159.00	160.02	159.96	160.01	156.02
Max	278.01	295.36	278.01	360.02	278.01	400.00

strained, 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.

C.7 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. 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:

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

The bandwidth w controls the degree of smoothing, with a larger bandwidth smoothing the curve more. I set $w =$ USD 10/MWh in the estimation, which is 11 percent of the mean unconstrained market-clearing price and 0.21 standard deviations in this price. Own-supply is smoothed in a similar manner. 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.

Table C11: Robustness of Estimated Marginal Costs (USD/MWh)

	IV = No, w = 10		IV = No, w = 15		IV = Yes, w = 10	
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)
93.35	75.66	(7.44)	76.36	(5.81)	84.42	(6.93)
60.41	47.18	(1.79)	48.94	(1.94)	57.47	(2.80)
73.39	56.85	(3.20)	57.59	(2.99)	68.91	(4.49)
87.54	82.64	(6.21)	83.27	(7.60)	100.01	(7.61)
73.20	61.68	(1.37)	60.92	(1.58)	64.32	(1.55)
48.46	36.66	(1.09)	36.59	(1.00)	39.98	(1.14)
91.32	80.71	(2.22)	80.22	(2.11)	80.90	(2.02)
35.98	19.17	(1.07)	19.24	(1.08)	20.58	(1.32)
66.86	58.56	(0.79)	58.28	(0.94)	59.68	(1.01)
109.98	62.30	(2.84)	67.32	(2.91)	65.64	(3.43)
132.39	118.86	(3.95)	119.17	(3.56)	121.05	(3.94)
36.57	45.33	(0.52)	44.46	(0.53)	45.06	(0.76)
14.90	14.08	(1.97)	10.53	(1.24)	14.32	(2.12)
			Column Means			
71.10	58.44		58.68		63.25	

The table shows robustness checks for the cost estimates of Table 5. The rows represent strategic sellers ordered as in that table. 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. Columns 2 and 3 give the coefficients and standard errors for the estimates without instrumental variables and with a bandwidth of USD 10/MWh for smoothing residual demand. Columns 4 and 5 give estimates using a larger bandwidth of USD 15/MWh. Columns 6 and 7 give the Table 5 estimates at the original bandwidth and using lagged temperature as an instrument for the moment conditions, on the assumption that lagged temperature shifts expected demand but does not affect supply shocks. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement from the set of moment conditions.

In Table C11 I test the robustness of the cost estimates to different smoothing parameters and to not instrumenting the moment conditions with lagged temperature.

The main IV estimates of marginal cost are in column 6 and column 2 reports estimates without instruments. The mean marginal cost estimates across all bidders is a modest 8 percent higher in the main IV estimates, reducing bidder margins, and the mean absolute deviation between the baseline and IV estimates is also 8 percent. Endogeneity of bids driven by cost shocks appears a mild concern in this market, perhaps because few supply shocks are realized by the time offers are made, a day ahead of delivery.

In column (4) I present estimates of marginal cost without IV using a smoothing parameter 50 percent larger than in the baseline case (i.e., $w =$ USD 15/MWh instead of USD 10/MWh). 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. The estimates are practically unchanged, with the mean cost estimate higher by 0.42 percent and the mean absolute deviation over all cost estimates only 3.42 percent, relative to column (2). The estimated costs thus do not appear very sensitive to a marginal change in the degree of smoothing.

D Appendix: Counterfactual model equilibrium and robustness

D.1 Cournot model equilibrium conditions and solution method

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 a 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. For now, take the division of the market into regions g as exogenously given; I will discuss how the regions are determined below.

The derivative of profit with respect to the seller's offered quantity q_{it} is:

$$f_{it}(q_{it}) = \tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L}_t) + q_{it}\tilde{P}^{g\prime}(Q^g|\sigma_{-it}, \mathcal{L}_t)) - \gamma_i. \tag{7}$$

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. The form of this problem is a mixed-integer complementary problem, since the equilibrium conditions are complementarity conditions between capacity constraints binding and the firm's first-order condition for an interior quantity. 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 decrease quantity.

The conditions for profit maximization depend on the first and second derivatives of inverse residual demand with respect to quantity. I represent inverse residual demand function $\tilde{P}^g$ as a set of whole quantities and incremental prices and smooth over quantities, with the same kernel-smoothing method described in , in order to approximate the derivative of inverse residual demand. When smoothing over quantity I use a bandwidth w_q equal to twenty percent of the range of quantities spanned by the residual demand curve.

The problem is linear in q_{it} if one neglects the effect of each seller's quantity on the aggregate Q^g. Similarly to Bushnell, Mansur and Saravia (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). This algorithm solves a linear complementarity problem for a vector of q_{it} on each iteration and then sequentially updates Q^g to formulate another linear problem, repeating the process until convergence. 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.

The regions g into which the grid is divided are determined by nesting the Cournot problem within the market-splitting algorithm, described in Appendix C C.3, which deals with constraints in practice. The treatment of congestion in the counterfactuals is therefore the same as in estimation. That is, the Cournot model is first solved on the unconstrained grid, and the equilibrium prices, quantities and inter-regional flows are calculated. If these flows and the implied regional imports and exports violate any transmission constraints, then those constraints are assumed binding, and a new Cournot equilibrium is solved on the grid divided by these constraints. For each iteration of the congestion or market-splitting algorithm, the residual demand curve is assembled and smoothed within each constrained area. In this way bidders in the Cournot model face the constrained residual demand within their region, treating the constraints themselves as perfectly inelastic imports or exports. Iterations continue until an equilibrium is found and no additional constraints bind, as described in the market-splitting algorithm.

The implication of this algorithm for the model is that strategic sellers behave with certainty that the grid constraints will bind as they do in equilibrium, and that strategic sellers account for the effects of inelastic equilibrium imports and exports in their bids. The first-order conditions of strategic sellers are confined to their constrained regions, and will be altered by both the slope and the level effects described in Section I II.C. Strategic sellers do not, however, 'see through' the iterations of the market-splitting constraint to account for the endogeneity of the constraints with respect to their bids. This assumption strongly simplifies the problem and is realistic given the relative non-concentration of the unconstrained grid.

D.2 Uniqueness of equilibrium

The Cournot model used does not theoretically guarantee a unique equilibrium here, for two reasons. 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 exist if the two regions have different monopoly prices and the transmission capacity is small (Borenstein, Bushnell and Stoft, 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.

Empirically, I search for multiple equilibria, by starting the equilibrium search at different quantities, but generally find a unique equilibrium for every hour. In the baseline simulation I initialize the search for an equilibrium at the point where all strategic sellers have equal quantities and supply 75 percent 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 selected by firms, in accord with the discussion of Section III III.B. I test for the importance of equilibrium selection by instead allocating strategic sellers 25 percent of the maximum residual demand to start. This produces an average unconstrained market price of USD 73.78/MWh over the sample period, indistinguishable from the price of USD 73.74/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.

Therefore, though I cannot rule out multiple equilibria, multiplicity does not appear to be important in practice. I speculate that this 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 C2, Panel B.[39] In principle, this can create distinct concave portions of residual demand where equilibria might be found. In practice, though, the potential equilibrium 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, even if it brings prices down.

D.3 Model fit

Table D12, Panel A, compares unconstrained market clearance with the bids actually submitted, in columns 1 and 2, with outcomes for the unconstrained Cournot model, in columns

[39] 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.

3 and 4. I present the unconstrained clearance of the submitted bids for reference, but consider it an inappropriate benchmark for whether the model matches market conduct, because it runs unconstrained clearance using bids that were offered in a constrained environment. The model overpredicts unconstrained quantity, shown in Panel A, and therefore underpredicts unconstrained price by 13 percent (USD 11.5/MWh on a base of USD 87.1/MWh). In reality, when firms bid, they know that they will face regional demand and be paid based on constrained, regional prices. This implies that an 'unconstrained' market, calculated by turning off transmission constraints but not changing bids, should have lower quantities than predicted by the model, as is observed.

Table D12, Panels B through D show that the model matches constrained market outcomes—that is, true market outcomes—extremely well, especially considering the parsimonious specification of costs. The North region is import constrained with respect to the West region 17 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 USD 28.2/MWh in the model and USD 33.7/MWh in the actual market clearance.

The model does a good job of fitting the pattern of prices over the course of the day. Table D12, Panels A through C show mean prices within four blocks of the day, from 1 to 6 in the morning, 7 to 12 noon, 1 pm to 6 pm and 7 pm to midnight. In the North region, prices rise from USD 58/MWh to USD 104/MWh from the early morning to the evening, before falling back somewhat at night. The model, while slightly underpredicting price on average, matches this pattern, with a predicted rise in prices from USD 56/MWh in the early morning to USD 98/MWh in the evening. A similar, though somewhat less steep, intraday pattern in prices is observed in the South 1 region (Panel C), both in the data and in the model. In the model, firms are assumed to have constant marginal costs, which in principle could make it difficult to match peak prices, if those prices are driven by firms moving out along convex cost curves. The good fit of the model to the intraday pattern of prices suggests that it is instead changes in demand, congestion and bidding that produce price fluctuations over the course of a day.

The model also fits the pattern of net demand between regions of the grid. The North region and West region have similar average 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 USD 32.9/MWh in fact and USD 39.5/MWh in the model.

D.4 Robustness of counterfactuals

The counterfactual estimates in the paper use the maximum monthly volume offered as a measure of firm capacity in that month. It is possible that capacity is greater than the monthly maximum offered, for example if firms are strategically withholding during periods of high congestion. Table D13 compares the counterfactual gains in surplus under the baseline capacity constraints (Panel A) to those under looser capacity constraints (Panel B), taken as the maximum volume offered across the whole sample. The change in surplus from transmission expansion to the North region does not depend on capacity constraints (USD 3.8 thousand per hour under monthly constraints and USD 3.5 thousand per hour under sample constraints). The change in surplus from a transmission expansion to the South region is somewhat higher under the looser capacity constraints. For example, the change in surplus due to a 1200 MW transmission expansion into the South region is USD 6.59 per hour under the monthly constraints and USD 8.24 per hour under the sample-wide constraints.

Table D12: Model Fit

	Actual Mean (1)	Actual Std Dev (2)	Model Mean (3)	Model Std Dev (4)
Panel A. Unconstrained				
Clearing price (USD/MWh)	87.06	48.52	80.11	40.11
Price hours 1 - 6	61.25	46.32	58.38	37.38
Price hours 7 - 12	94.56	36.96	85.31	32.45
Price hours 13 - 18	100.16	47.18	91.48	40.31
Price hours 19 - 24	92.26	52.57	85.28	41.33
Clearing quantity (MW)	936.82	328.64	1123.97	436.17
Panel B. Constrained, North region				
Clearing price (USD/MWh)	86.85	48.52	82.33	41.32
Price hours 1 - 6	58.44	44.72	56.03	36.53
Price hours 7 - 12	97.25	37.52	92.56	34.46
Price hours 13 - 18	103.86	46.44	97.84	40.21
Price hours 19 - 24	87.86	51.52	82.89	40.68
Price $>$ West price (% of hrs)	0.18	0.39	0.22	0.42
Price $-$ West Price (if not equal)	33.71	21.84	33.73	25.78
Demand (MW)	409.91	240.18	498.11	264.54
Supply (MW)	151.46	149.16	165.47	206.41
Net demand (MW)	258.45	244.49	332.64	241.24
Panel C. Constrained, South 1 region				
Clearing price (USD/MWh)	88.39	51.20	86.85	46.86
Price hours 1 - 6	69.12	52.51	69.71	48.80
Price hours 7 - 12	92.27	42.79	91.48	41.37
Price hours 13 - 18	98.11	49.99	95.33	45.78
Price hours 19 - 24	94.06	53.77	90.89	46.86
Price $>$ West price (% of hrs)	0.23	0.42	0.33	0.47
Price $-$ West Price (if not equal)	32.94	24.58	37.56	24.40
Demand (MW)	61.66	145.83	62.64	145.77
Supply (MW)	142.75	87.77	146.61	92.93
Net demand (MW)	-81.10	180.84	-83.97	184.37
Panel D. Constrained, West region				
Price (USD/MWh)	80.72	48.06	74.98	41.26
Demand (MW)	109.53	143.30	112.58	142.75
Supply (MW)	455.65	222.36	537.94	256.20
Net demand (MW)	-346.12	247.01	-425.36	276.82

The table shows the fit of the Cournot model to market outcomes on the day-ahead market from November, 2009 through April, 2010. In each panel the first two columns show the mean and standard deviation of each outcome for the actual market clearance, using the bids submitted to the exchange. Columns 3 and 4 show market outcomes under the Cournot model equilibrium. The Panels represent different treatments of transmission constraints. In Panel A the clearance is conducted and the model is solved assuming no transmission constraints exist. Note that the unconstrained clearance benchmark of Panel A, columns 1 and 2, commonly used by the exchange, is itself a naïve counterfactual, conducted using bids submitted under constrained conditions. In Panels B through D, market outcomes from constrained clearance are shown using bids as submitted and as predicted by the model.

Table D13: Counterfactual Market Outcomes with Expanded Transmission Capacity

		North		South	
Transmission expansion	None (1)	400 MW (2)	1200 MW (3)	400 MW (4)	1200 MW (5)
	Panel A. Fixed Cournot bids				
Regional Prices					
North > West (% of hrs)	0.22	0.06	0.01	0.21	0.21
North − West (USD/MWh)	33.73	33.72	36.82	31.60	31.17
South 1 > West (% of hrs)	0.33	0.28	0.28	0.07	0.00
South 1 - West (USD/MWh)	37.56	37.46	37.55	29.53	36.17
Quantity (MW)					
North net demand	332.64	378.56	390.84	287.38	270.96
South 1 net demand	-83.97	-90.94	-92.96	-50.27	-32.39
West net demand	-425.36	-432.32	-438.50	-434.24	-435.67
Strategic seller cleared	535.98	535.98	535.98	535.98	535.98
Surplus (USD '000s)					
Surplus plus congestion rent	57.12	58.62	58.85	58.95	59.45
Congestion rent	4.12	3.36	2.51	3.34	2.35
Surplus	53.00	55.26	56.35	55.61	57.10
Buyer's	17.88	18.92	19.14	17.67	18.12
Seller's	35.13	36.34	37.21	37.94	38.98
	Panel B. Cournot competition, sample capacity constraint				
Regional Prices					
North > West (% of hrs)	0.23	0.14	0.05	0.23	0.23
North − West (USD/MWh)	33.13	31.45	35.09	31.65	32.36
South 1 > West (% of hrs)	0.35	0.34	0.33	0.12	0.04
South 1 - West (USD/MWh)	38.76	38.03	37.98	33.58	33.17
Quantity (MW)					
North net demand	358.15	424.56	465.13	319.81	294.73
South 1 net demand	-82.60	-86.73	-88.10	-32.27	11.70
West net demand	-457.68	-507.01	-537.22	-505.63	-525.12
Strategic seller cleared	573.97	593.41	610.35	639.67	671.79
Surplus (USD '000s)					
Surplus plus congestion rent	60.85	63.41	65.04	65.63	67.68
Congestion rent	4.53	5.02	3.85	4.79	3.89
Surplus	56.32	58.39	61.19	60.84	63.79
Buyer's	19.93	20.75	22.49	22.71	24.60
Seller's	36.40	37.65	38.70	38.13	39.19

The table shows counterfactual market outcomes under different increases in transmission capacity. Panel A shows a naïve counterfactual where transmission expansion occurs but strategic sellesr continue to offer the same quantity bids as they did in the Cournot equilibrium without expansion. Panel B shows a Cournot counterfactual where capacity constraints are relaxed to the maximum quantity offered by each firm in the whole sample. The counterfactual scenarios, across columns, are (1) no change in transmission (baseline case) (2) 400 MW expansion to the North region (3) 1200 MW expansion to the North region (4) 400 MW expansion to the South region (5) 1200 MW expansion to the North region. The groups of rows in the table show how market prices, quantities and surplus respond in each scenario. The notation North − West (USD/MWh) means the difference in the respective regional prices conditional on congestion.