King Abdullah Petroleum Studies and Research Center

Potential Gains From Reforming Price Caps in China's Power Sector

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Key Points

When energy sectors transition from government-controlled to market-driven systems, the legacy regulatory instruments can create unintended market distortions and lead to higher costs. In China, the most notable regulatory throwback is ceilings on electricity prices that generators can charge utilities, which are specified by plant type and region. We built a mixed complementarity model calibrated to 2012 data to examine the impact of these price caps on the electricity and coal sectors. Our study highlights the following major findings:

Capped on-grid tariffs incentivize market concentration and vertical integration so that generators can cross-subsidize power plants, ensure an uninterrupted supply of fuel and reduce the impact of volatility in fuel prices.

Tight price caps can cause the system to deviate from the least-cost capacity and fuel mix. In 2012, this resulted in an additional annual cost of at least 45 billion RMB, or 4 percent of China's total power system cost. The government also had to subsidize some of the losses, which indicates that this regulatory design is not responsive to market realities.

Price constraints can impact the outcomes of other policy initiatives causing them to veer from intended goals. In the case of China, according to our modeling, greater installed wind capacity does not have a significant impact on the amount of coal consumed. Also, abolishing restrictive tariff caps on coal-fired generation does not increase coal use because the utilization rate of peak-shaving coal plants drops.

We also estimate, using the model, subsidies required for a range of wind capacity additions to China's power generation mix and find that the feed-in tariff could have been less generous.

Executive Summary

China's past reforms have moved its electricity sector to the middle ground between fully functioning markets and a command system. The price formation mechanism in particular is still heavily regulated with the government capping prices at which generators sell to utilities. These price caps, which differ by region and generation technology, are designed to limit electricity costs while reflecting market conditions and promoting or restricting a particular technology or fuel type. However, the caps increase costs because the frequency of the price cap adjustments do not always match market movements, and this is especially evident when compared against the deregulated domestic coal sector.

Chinese utilities are the sole buyers of power in their regions, making them monopsonists. They can lessen the effect of the on-grid tariff caps by using their market power to redistribute the number of generation hours among contracted power plants and, consequently, price more capacity below the caps. Often such a redistribution does not match the least-cost solution that would have been available without the caps. The power generators can both improve their profits and lower the cost to the utilities by acquiring an array of power plants that run on a mix of technologies, which are cross-subsidized profitably in contracts with the utilities. The acquisition of multiple plants by producers increases the market concentration of generation.

The risk of volatile coal prices due to the deregulation of coal in association with capped coal-fired generation tariffs that don't allow excess payment schemes – such as fuel adjustment clauses – to cover such fluctuations, encourages vertical integration to alleviate fluctuations in fuel costs and ensure uninterrupted supply. However, the losses incurred by power generators as well as various subsidies received from national and provincial governments suggest that these strategies are insufficient to mitigate distortions caused by the price caps.

In order to assess the effect of the on-grid tariff caps, we designed a bottom-up, mixed-complementarity problem (MCP) model that represents Chinese coal and power sectors and minimizes the total systems costs with and without market-altering regulations. We calibrated the model based on 2012 data and developed a set of scenarios to illustrate the impact of China's price control policies on power generation within the current energy system and under a range of wind capacity targets.

We found that price deregulation eliminates generators' losses and the need for cross-subsidization among power generation technologies, and would have resulted in at least 45 billion RMB of cost savings in 2012, or equal to 4 percent of the power system costs. It also facilitates grid integration because regions no longer need to hoard base-load generation to stay blow the caps and, consequently, raises interregional electricity trade by 234 terawatt-hours. This increased power transmission would eliminate 6 percent of physical coal transportation, reducing required investment in coal railway infrastructure.

Abolishing restrictive tariff caps on coal-fired generation does not increase coal consumption because of a drop in the utilization of coal plants used for peak shaving. On the other hand, forcing significant wind capacity into the market also does not substantially reduce coal use due to coal's cost competitiveness.

Deregulation increases the amount of government subsidies required to bring wind capacity online by shifting the cost burden from the utilities. However, as installed wind capacity increases, the demand for coal decreases, lowering the price of coal. As a result, the revenue constraint is relaxed and the effect of distortions due to the caps is also reduced. This conclusion holds true as long as the Chinese regulators do not reduce the caps in response to lower coal prices.

Assessing the Effects of Electricity Price Caps

In the past decade, China has introduced many reforms to its power sector and fuel markets, moving to a more market-oriented energy system, yet maintaining significant government controls. Unlike the restructured spot and capacity markets in the U.S. and Europe, the current Chinese system is organized around government-owned utilities that operate the grid and purchase power under long-term contracts from generators. A major government restriction is that the National Development and Reform Commission (NDRC) caps the prices (on-grid tariffs) a utility pays a generator for electricity, with the caps differentiated by technology and region.

Credit Suisse (2012) and Akkemik and Li (2015) identify the disconnect between market-based coal prices and the rigidity of on-grid tariffs as a fundamental issue confronting the Chinese electricity sector. The price caps have the potential to complicate policies aimed at meeting ambitious capacity development and renewables targets for 2020 in China's Energy Development Strategic Action Plan (State Council, 2014).

The Chinese authorities are in the process of reforming the price-cap policy (State Council, 2015; NDRC and NEA, 2015) and some proposals have been studied (Zeng et al., 2015 and Zhang, 2012). To estimate the benefits of reform, we model the Chinese electricity sector as an economic equilibrium, formulated as a MCP where every regional grid ("utility") acts as a Stackelberg leader.

To our knowledge, our study is the first to model the Chinese tariff caps. We connect three different strands of research. First, we develop a bottom-up model with detailed representations of technologies and regional breakdowns for analyzing the Chinese power sector. This approach allows us to address a wide range of policy scenarios, including the sector's strategic development plan (Cheng et al., 2015 and Chandler et al., 2013), the costs of policies for meeting emission control targets (Li et al., 2014; Dai et al., 2016 and Zhang et al. 2013), and the opportunities for developing interregional integration of electricity markets (Gnansounou and Dong, 2004). A number of studies also explore the integration of renewables (Despres et al., 2015 and Lu et al., 2013) and the effect of renewable energy quotas (Xiong et al., 2014) on the power sector.

Second, since we link the coal sector with the electricity sector, our study relates to literature examining cross-sectoral interactions of policies. Kuby et al. (1993, 1995) and Xie and Kuby (1997) explore development options for coal and electricity delivery and Chen (2014) studies the effects of coal price fluctuations on the other sectors in the Chinese economy.

Third, we add to the MCP literature (see Gabriel et al., (2013) for a review of the this literature), to show how price caps and subsidies can be represented in MCPs through direct manipulation of both primal (physical) and dual (prices) variables, expanding on Matar et al. (2015) and Murphy et al. (2016).

We examine the following questions:

> How efficient is the current electricity market with on-grid price caps compared with a deregulated market?

What are the effects of the price caps on the utilization and value of existing capacity, investment decisions, energy flows and the development of wind power?

What are the cross-sector effects of the existing pricing policy?

What is the effect of increased wind penetration on the coal and electricity sectors?

Power Market Structure and On-grid Tariffs

China's electricity sector consists of a mix of publicly and privately-owned entities. The last major structural transformation occurred in 2002 with the dismantling of the State Power Corporation (Liu, 2013), resulting in limited competition in power generation. However, market concentration remains high with the top five companies accounting for about 50 percent of the sector (Epikhina, 2015). Hubbard (2015) measures ultimate ownership, finding that the Herfindahl-Hirschman Index of company generation revenues at the national level reaches 0.222 for thermal, 0.220 for hydroelectric and 1 for nuclear power. He also estimates that central and local state-owned enterprises control 83 percent of thermal, 84 percent of hydroelectric and 100 percent of nuclear power generation.

Two monopolies owned by the national government operate the transmission and distribution systems: the State Grid and the South Grid. These utilities are the sole purchasers of power from generators, buying under long-term contracts and selling to consumers at government-controlled prices in their regional markets. NDRC determines the maximum reference prices that generators can charge (on-grid tariff caps) to cover their total costs, including fuel.

Table 1 below shows the price caps applicable to each technology and region. Note that the coal price caps vary significantly by region. Since coal is far cheaper than other fuels, coal generated 76 percent of total electricity produced in 2012 (World Bank, 2016) and coal plants provide spinning reserves despite the higher capital costs.

Table 1. Average on-grid tariffs caps for selected regions in 2012 (RMB/MWh).*

Regions	Technologies				
	Coal	**Gas**	**Nuclear**	**Hydro**	**Wind****
Coal Country***	310	573	387	300	610
East	460	573	387	305	610
South	550	573	377	237	610
Central	480	579	387	350	610
Northeast	415	573	380	300	564

Source: NDRC.

* Average exchange rate in 2012: 1 RMB = 0.1584 USD (China Statistical Yearbook, 2015).

**The tariffs for wind are the feed-in tariffs.

***Refers to Shanxi, Shaanxi, Ningxia and Inner Mongolia.

The caps are adjusted to reflect conditions in fuel markets, or to promote or restrict a particular technology. Typically, this is done annually but can also be done more frequently. However, these adjustments do not always respond in tandem with changes in fuel prices. Figure 1 below illustrates the producer price indices based on the mine-mouth prices for coal and the prices generators receive for their electricity, illustrating the increasing discrepancy between deregulated coal prices and what generators charge for their electricity. In 2012, the government abolished mandatory long-term contracts and the allocation of railway capacity to coal sold under long-term contracts, establishing a liberalized coal market and exposing generators to greater price risk during the periods between standard annual adjustments to the electricity price caps.

Price caps are used in many countries to limit price volatility and curtail market power in electricity markets. However, the price caps in China differ substantially from those in standard electricity markets with spot-market auctions. Typically, a very high cap is imposed on all generators, limiting prices in extreme situations where only one or a few generators are available to provide incremental power during unforeseen events such as plant outages or abnormally high demand. These caps limit transient price spikes but still provide returns

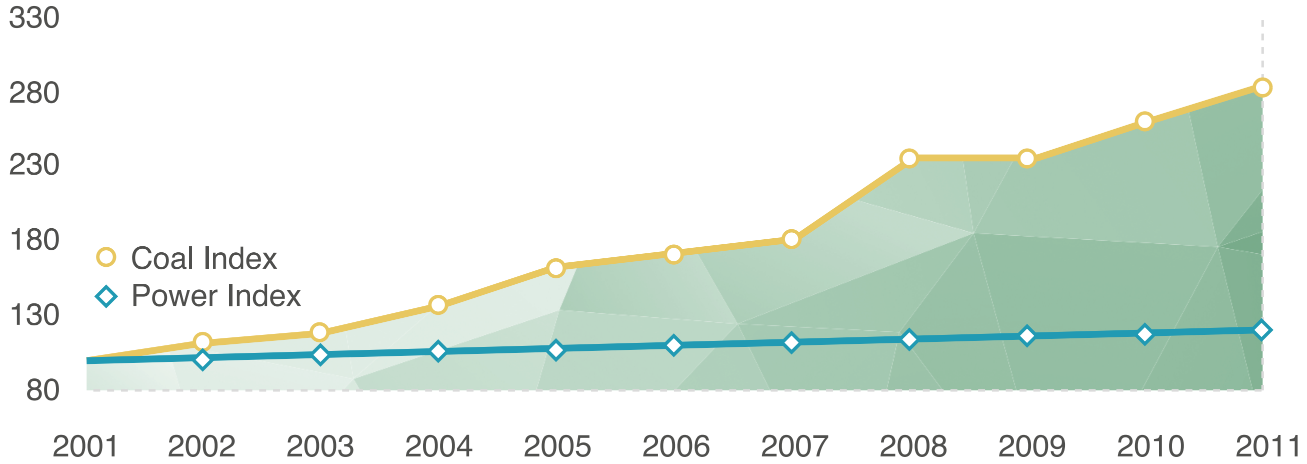

Figure 1. Producer price indices for coal production and electricity generation (2001 – base year).

Source: CEIC 2016.

that incentivize long-run investment. Furthermore, to provide reserves, after the generation auction, a second auction provides a market for capacity where generators are paid to be available, even if they do not send electricity into the grid; the Chinese market has no standard payment mechanism for making capacity available.

Since the Chinese electricity market pays only for dispatched kilowatt hours, has binding price caps on long-term contracts and has a single buyer in each region, a model of the sector is inevitably different from that which is representative of other systems. Chinese utilities operate in defined territories and own the grid, and as a result they can exercise monopsony power over the generators. As a result, the Chinese electricity sector yields low profits despite its market concentration (Hubbard, 2015). This makes them Stackelberg leaders that can drive contract prices to cost, which includes a fair rate of return, and incentivizes firms to have a portfolio of power plants by paying the cost of cross-subsidization. Figure 2 below shows the cost per kilowatt-hour as a function of plant utilization, assuming an annualized per-kilowatt-hour capital cost and an operating cost that is constant per kilowatt-hour. The per-kilowatt-hour total cost is the sum of the per-kilowatt-hour variable cost, plus the annualized investment cost divided by kilowatt-hours of operation.

A plant that is utilized less than $\hat{h}$ hours in a year is unprofitable with a price cap of $\hat{p}$. Thus, if this plant was used to meet peak load and provide reserves for grid reliability, it would not be profitable and would not be built without special arrangements.

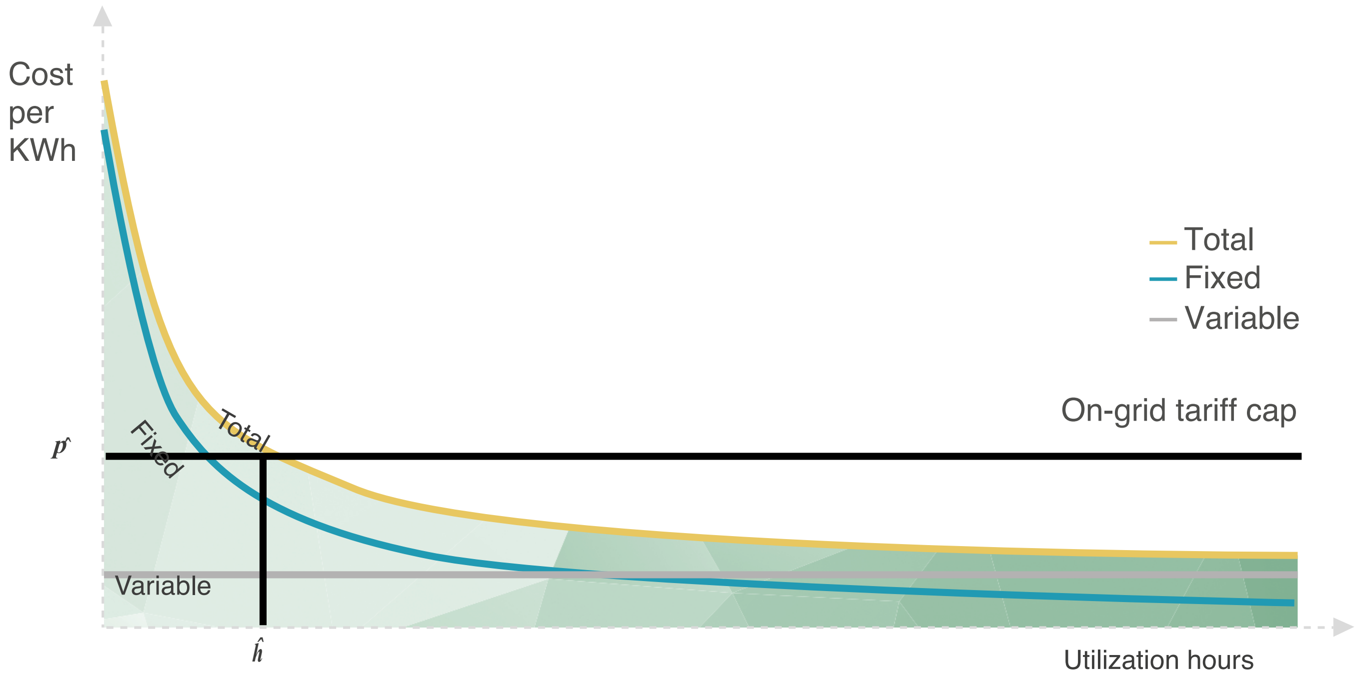

Figure 2. Monopsony price (average cost) as a function of utilization for a plant year).

Source: KAPSARC.

Market Adaptation to Price Regulation

Utilities and generators can respond in three ways to ensure they have sufficient generation capacity despite binding price caps. The first matches the least-cost capacity mix, the second distorts this mix and a third increases the value of market concentration in generation. These responses are described in the text box below.

Conceptualizing the Market Response to Price Caps

First, let the least-cost generation plan without caps set the lowest number of operating hours for a plant of type *A* at h_A^{min} and assume $h_A^{min} \leq \hat{h}_A$, the lowest number of hours of operation for a plant to remain profitable at the price cap, see Figure 3 below. Let h^{av}_A be the average hours of generation by plants of type *A* in the least-cost generation plan. If $h^{av}_A > \hat{h}_A$, then, the utility can achieve the least cost by paying the price $p(h^{av}_A)$ to all generators and dispatch the plants such that each has an average utilization of h^{av}_A.

Figure 3 also represents the second solution: distortion of the power mix. It shows the average cost curves for two plant types, *A* and *B*. *A* has higher fixed costs and lower variable costs than *B*. The point where the total cost per kilowatt-hour of A and B are equal is the maximum number of operating hours for a plant of type B, $h_B^{max} = h_A^{min}$. Let h_B^{min} and h^{av}_B be the minimum and average operating hours for plant *B* in the minimum-cost solution and $\hat{h}_B$ be the minimum hours for *B* to be profitable. Let $h^{av}_B < \hat{h}_B$, then the generator cannot have capacity operate at h_B^{min} and remain profitable by just averaging over plants of type *B*. Let $h_B^{min,av} > h_B^{min}$ be the lowest utilization of plants *B* with a recalculated $h^{av}_B = \hat{h}_B$. Because the total cost of plant *B* at h_B^{max} is the same as the cost of plant *A* at h_A^{min}, the marginal cost of increasing h_B^{max} and h_A^{min} by ϵ starts at *0* and increases with larger ϵ. Increasing h_B^{max} and h_A^{min} allows us to decrease $h_B^{min,av}$, keeping $h^{av}_B = \hat{h}_B$ and lowering costs. This can be done until the costs to the utility increase. This solution deviates from the least-cost solution without caps.

On top of the first and second strategies, if the average price paid for plants of type *A* is below $p_{\hat{A}}$ because $h^{av}_A > \hat{h}_A$ and the average utilization of capacity of type *B* falls below $\hat{h}_B$, then the utility can pay up to $p_{\hat{A}}$ when the generator supplies a bundle of both capacity types with the price for capacity of type *B* at the price cap of $p_{\hat{B}}$. This cross-technology subsidization adds value to market concentration in a utility's service territory and impedes competition.

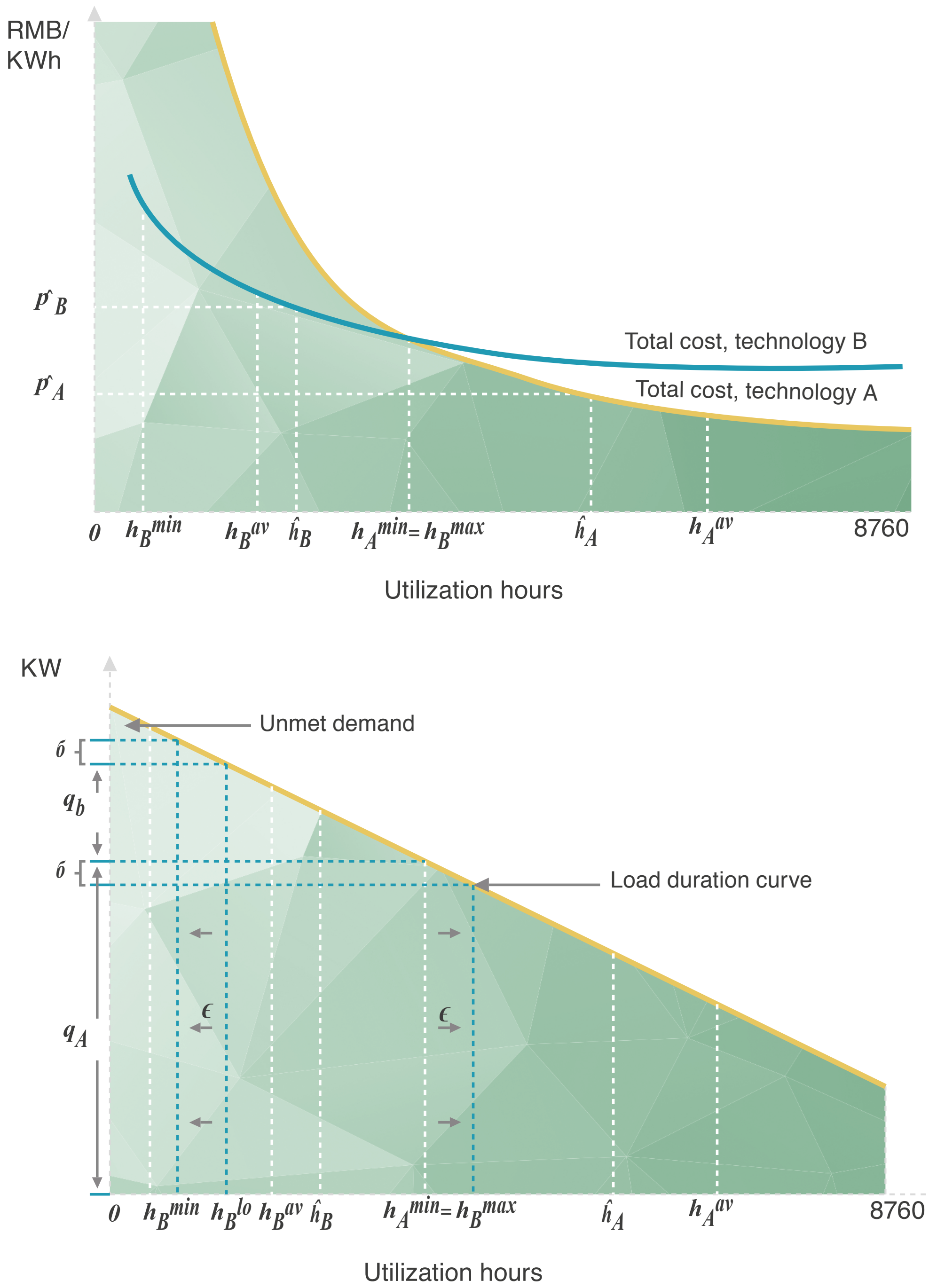

Figure 3. Effect of on-grid tariff caps on capacity mix.

The model represents all of these strategies in one revenue sufficiency constraint per utility region. When this constraint is binding, the plant mix is distorted. When it is not satisfied, we used the model to find the smallest subsidy necessary to be feasible. National and provincial governments subsidize input costs using reduced fuel costs, soft loans and land-use rights among other strategies (China Coal Resource, 2009, 2011; Reuters, 2011, 2015; and Liu, 2012). Alternatively, a state-owned generator can have other businesses that cover its losses, even though a private generator has no incentive to cross-subsidize electricity generation and lower its profits. These measures reduce the losses of power generation companies but don't address the structural problems that cause them.

The Government Response

Because of the market distortions described above and the need to subsidize some peak-load generation, the Chinese government is considering new reforms. In 2015, the State Council released general guidelines for advancing reforms in the electricity sector, followed by a joint NDRC/NEA document on improving operations and regulations. The reforms emphasized market mechanisms and proposed significant changes in the sector's structure and pricing policies:

Direct supply: Large energy consumers will be able to purchase electricity from power plants at negotiated prices.

Liberalized wholesale and retail markets: Independent electricity companies will have market access, buying power from generators, each other and, potentially, from consumers.

Promotion of renewables: Grid companies and utilities purchase renewables (excluding hydro) at the benchmark tariff applied to coal-fired generation.

Changes in the price formation mechanism:

- On-grid tariffs: Competitive pricing based on benchmark tariffs.
- Transmission and distribution tariffs: Set by the government.
- Prices for residents, agriculture and social service sectors: Controlled by the central government.
- Prices for the industrial and commercial sectors: Shift from prices proposed by the provincial government and approved by the central government to direct negotiations between buyers and sellers.

A pilot reform program was rolled out in Inner Mongolia and Shenzhen City and subsequently expanded to include Anhui, Hubei, Yunnan and Guizhou provinces as well as the autonomous region of Ningxia.

Modeling Approach

Three groups of players define the structure of the Chinese power market: 1. The central and provincial governments that set the rules; 2. Utilities owned by the national government that own the grid and are the sole purchasers of power in their territories; and 3. Government-owned and private-sector firms that generate power under contract to utilities. The utilities and generators are players in a Stackelberg game with the utilities being the leaders and the generators the followers who can be forced to offer electricity based on cost. This game can be modeled presuming the utilities minimize their costs subject to the NDRC's pricing restrictions. The utilities can also trade electricity with each other to reduce total system cost subject to on-grid tariff regulation.

The power model minimizes the costs of electricity plant construction and generation over a mix of technologies and the costs of construction and operation of the transmission and distribution grid, satisfying an exogenous power demand. We add a revenue constraint in each region for the generators that ensures the costs incurred by generators across all the plants do not exceed the revenues, given the price caps. Having one binding revenue constraint for all generators implies that some generators must have a mix of plants to be profitable. A high level of market concentration gives generators the ability to balance their profits and losses over a portfolio of plants.

The revenue constraint takes into account all costs incurred by generators in the region, including fuel costs. The prices of coal are endogenous in the model and come from dual variables in the coal supply model. This means that dual variables appear in the revenue constraints. Consequently, the price cap cannot be represented in an optimization model of the combined coal and electricity system and we formulate the Stackelberg game as an MCP.

When comparing the implications of the caps versus deregulation, we set wind capacity at its 2012 level and find the subsidy levels necessary to produce that quantity. We did not model the feed-in tariffs directly because that would require inventorying the wind resources of China and building regional wind supply curves, using information we do not have.

Existing environmental policies are modeled by capping sulfur dioxide (SO_2) and nitrous oxides (NOx) emissions at 2012 levels. Power demand is represented by regional load duration curves segmented into vertical load steps. The formulation of the power model is given in Appendix 1.

To capture the interactions between the coal and power sectors, we combine the power model with the coal-supply model described in Rioux et al. (2015) into a single MCP. Province-level supply curves feed coal production into a multimodal transshipment network that links domestic coal production and imports with the generators. The power sector buys coal in a liberalized coal supply market, with prices set to marginal costs, the dual variables associated with the coal supply constraints. The prices of other fuels, including natural gas, are fixed to the 2012 city-gate prices as seen by power producers, and end-use demands are set to 2012 levels.

All scenarios include existing capacity from 2012. The policy comparisons are made using long-term, single-period scenarios that allow additions to capacity when it is profitable to displace existing plants. Capacity costs are single-year annuitized costs, and operating costs are presumed to be the same throughout the life of the equipment. This formulation can be thought of as a myopic view where the fuel and operating costs in the chosen year are used in determining the overall and mix of capacity that will be needed. The sources of the data used for the calibration year, 2012, are detailed in Appendix 2.

Three scenarios illustrate the impact of China's on-grid tariff policies and a set of scenarios were created to examine the effect of ranging on wind capacity.

> Calibration: This short-run scenario replicates what actually happened in 2012 in the coal and power markets with the capacities available then, which allows us to benchmark our model. The on-grid prices are capped by the maximum on-grid tariffs.

> Long-run Regulated: The on-grid prices are capped and capital investment is allowed in both the coal and power sectors.

> Long-run Deregulated: The caps are removed and capital investment is allowed in both the coal and power sectors.

> Wind Scenarios: For the regulated and deregulated cases we range on the wind capacities and estimate the associated subsidies resulting from the 2012 feed-in tariff.

Establishing the Baseline

In a rapidly evolving market such as China, the existing capacity mix is not necessarily the most efficient. Furthermore, coal markets experienced bottlenecks in 2012 that were subsequently removed. To isolate the effects of the price caps from other aspects of the electricity sector, we make the Long-run Regulated scenario the baseline for estimating the impacts of alternative policies in comparison to current policies.

Under the Long-run Regulated scenario the energy mix changes versus the Calibration scenario: the share of thermal power decreases — primarily coal-fired generation — from 75.7 percent to 70.1 percent, compensated by increased nuclear (from 2 percent to 7.6 percent). The mix of coal plants shifts: 87 gigawatt of ultra-supercritical capacity is added and 98 gigawatt of existing coal plants are retired because of the inefficiencies of the legacy plants.

Reflecting actual developments in the Chinese coal market since 2012, the expansion of western coal production and increased capacity to transport coal lowers steam coal imports from 227 million tonnes to zero and reduces the weighted average price of delivered coal from 925 to 785 RMB/t. SCE.

Table 2 shows the weighted average marginal costs of electricity production across all load segments for five regions from the regulated scenarios and the average costs of generation, transmission and distribution. The average costs in the Calibration scenario are at between the residential and industrial/commercial tariffs, while the long-run average costs are at around the residential prices, indicating the extent of savings gained from improving the equipment mix and debottlenecking coal transportation. In the Calibration scenario, the large differences in the regional marginal costs

Table 2. Comparison of marginal supply cost with actual, 2012, end-user electricity tariffs (RMB/MWh).

	Regulated Scenarios Weighted Average Marginal Costs (average costs +T&D)		Actual End-user Tariffs	
Region (Province)	**Calibration**	**Long-run**	**Industrial and Commercial**	**Residential**
Northeast (Jilin)	1056(641)	373 (536)	917	515
North (Hebei)	1000(658)	336 (500)	733	470
Shandong	1972(690)	341 (504)	745	493
Coal Country (Shanxi)	323(536)	331 (495)	754	467
South (Guangdong)	656(644)	355 (549)	873	606

Sources: Polaris Power Grid, KAPSARC research.

reflect the congestion of both the transmission lines and the coal supply chains. The data suggest that commercial and industrial consumers cross-subsidize residential users. That is, not only are there cross-subsidies in generation, there are also cross-subsidies in consumption.

As we did not decrease the caps on coal plants despite the fall in coal prices, the total subsidies, from both the government and cross-subsidies from other businesses owned by generators, needed to ensure enough capacity drops from 217 billion RMB to 29 billion RMB. Thus, the amount of distortion due to the caps is lessened considerably. Given the price-cap changes in 2015, however, the government would probably cut the caps on coal generation in the Long-run Regulated scenario due to lower coal prices, increasing the amount of subsidies needed and raising inefficiencies.

In the Calibration scenario, the subsidy paid by the government to wind generators is the difference between the existing 2012 feed-in tariff and the on-grid tariff paid by the utilities times the kilowatt-hours of generation. The price paid by the utility to wind generators is capped at the maximum on-grid tariff for coal. In the long-run scenarios, rather than model the feed-in tariff, we require the existing capacity of 61 gigawatts to operate and calculate the subsidy needed to make that capacity economic. The subsidy necessary to have this level of capacity drops to 17 billion RMB in the Long-run Regulated scenario from 20 billion RMB of actual subsidies paid in the Calibration scenario.

Capping Prices Increases Costs

We now compare the market outcomes in the Long-run Deregulated and Long-run Regulated scenarios. Deregulation facilitates structural changes in the power market, eliminates generator losses and produces cost savings of 45 billion RMB, which constitutes 4 percent of the power system cost and 2.6 percent of the total system cost (See Table 3 below).

Eliminating the caps allows the utilities to freely contract with generators and meet demand in all load segments more efficiently. The utilities and power generators do not need to manipulate contracted utilization rates to keep average costs within the caps. As a result, investment in ultra-supercritical coal capacity, which is built extensively to achieve lower variable costs under the Long-run Regulated scenario, drops from 87 gigawatt to 41 gigawatt. Utilities are now able to contract with existing subcritical coal-fired generators for peak shaving. Despite contracting more capacity from the less efficient plants under deregulation, coal consumption and its environmental consequences remain essentially the same because the utilization of the coal plants drops with the removal of the price caps.

The subsidies and cross-subsidies to cover generator losses are eliminated with deregulation and wind subsidies increase by 800 million RMB. Total subsidies drop from 46 billion RMB to 17 billion RMB.

Removing the caps results in an additional 234 terawatt-hours of interregional electricity trade, a 30 percent increase. This increased grid integration is the result of eliminating distortions caused by the price caps. The Long-run Regulated scenario actually builds more transmission capacity. However, this new capacity is less efficient AC lines with low utilization that are added to increased plant utilization through peak shaving. With deregulation, inland coal-producing regions, such as Xinjiang and other western provinces, can produce more power and export it via the new UHV lines. The shift in coal production and expanded UHV lines reduce coal consumption in major Eastern importing provinces, such as Shandong. These provinces no longer need high-utilization capacity to cross-subsidize lower-utilization capacity. Increased power transmission also results in a 6 percent reduction in the ton-km movements of coal by rail and water. This leads to a reduction in needed new rail capacity of 1,250 km, saving 24 billion RMB in total rail investment costs.

Table 3. Total costs and the cost of price regulations (billion RMB).

Indicators	Calibration	Long-run Regulated	Long-run Deregulated
Total Systems Cost	1,971	1,789	1,745
Savings	-	182	227
Cost of Regulation	-	-	45

Source: KAPSARC research.

Despite lower interregional transmission under the price caps, generation is 2 percent higher compared to the Deregulated scenario. This is explained by higher plant losses as well as increased intraregional transmission for operating pumped hydro storage facilities. Pumped storage helps flatten the demand curve, relaxing the generators' revenue constraint under the price caps. (See Table 4 below).

In sum, deregulation lowers costs, results in more efficient interregional transmission, eliminates the need for generator subsidies and reduces the value of market concentration in power generation. Removing the tariff caps has a small impact on coal consumption and related emissions and does not increase significantly the subsidies necessary to bring wind into the energy mix. Our results are a lower bound on the benefits of deregulation because the price caps on coal generators in the Long-run Regulated scenario would probably have been lowered. China did this in 2015, due to the lower coal prices, exacerbating the effects of the caps, especially in raising the need for subsidies.

Table 4. Key indicators of China's power sector under various scenarios.

Indicators	Calibration	Long-run Regulated	Long-run Deregulated
Electricity Production, TWh			
Nuclear	99	380	365
Wind	102	102	102
Hydro	874	875	875
Thermal	3,930	3,661	3,576
Additional Capacity, GW			
Nuclear	-	36	34
Coal	-	87	41
High Voltage Transmission	-	248	183
Coal Consumption, mt SCE	1,236	1,089	1,079
Weighted Average Marginal Value of Coal, RMB/t SCE	925	785	730
Outgoing Interregional Transmission, TWh	516	775	1,009

Source: KAPSARC research.

Increasing Wind Capacity Mitigates the Effects of the Price Caps

In the scenarios presented here, we examine the effect of increasing wind capacity up to the total of 261 gigawatts for both the Long-term regulated and Deregulated cases. Table 5 below summarizes the results. The wind subsidy column shows the average of the regional minimum subsidies required for the target capacity to be built.

Several expected results are seen: In the Regulated and Deregulated scenarios the wind subsidy per megawatt-hour rises with increasing wind, while coal consumption and prices decrease. The total equilibrium cost generally increases, though not always monotonically. This is because even though the cost of the wind subsidy increases with the decreasing marginal value of wind, the cost of coal is falling. That is, there is no natural direction of change in the total cost. The average wind subsidy per kilowatt-hour increases except for the first increment of wind in the Deregulated scenario because the average efficiency of the existing plants is below that of new plants added in the wind-rich northern provinces.

In the Regulated scenarios, the decreases in coal prices with increasing wind power will loosen the revenue constraints, even though the addition of wind raises the difference between peak and base-load demands. This lessens the need for subsidies for generators and reduces the difference in cost between the Regulated and Deregulated scenarios. Additions of wind mitigate the effect of the price caps on the energy system while increasing the subsidy burden for the government. However, despite the substantial drop in coal prices under both Long-run scenarios, the subsidy required to bring existing plus as much as 150 megawatt of additional wind generation capacity online is below the actual range of 241 – 216 RMB per megawatt-hour (Zhao et al., 2014). These results suggest that the current level of wind-power subsidies — determined by the feed-in tariffs — is higher than required and the intention of Chinese policymakers to reduce it is justified.

Table 5. Total costs and the cost of price regulations (billion RMB).

Wind Capacity, GW	Equilibrium Total Cost billion RMB (excluding subsidies)	Average Wind Subsidy RMB/MWh	Coal Use mt SCE	Coal Price RMB/TCE	Generator Losses billion RBM	Cost of Tariff Cap Regulation billion RMB
Long-run Regulated Wind Scenarios						
61*	1,789	162	1089	785	29	45
111	1,803	178	1088	745	26	43
136	1,804	181	1087	735	19	37
161	1,813	183	1087	731	16	37
186	1,815	186	1087	721	14	30
211	1,800	212	1077	636	1	5
261	1,819	223	1047	591	-	4
Long-run Deregulated Wind Scenarios						
61*	1745	170	1079	730		
111	1760	157	1079	730		
136	1767	169	1078	690		
161	1776	180	1078	686		
186	1785	187	1076	668		
211	1795	197	1073	640		
261	1815	221	1041	588		

Source: KAPSARC research.

*Existing capacity.

Impact of Demand Shifts on the Coal Price

One of the interesting features of the results is that the coal price drops steeply for a small decrease in production. This is explained in Figure 4 (overleaf). In this figure Mine 1 serves cities 1 through 3 with increasing transportation costs t_1, t_2, and t_3. Mine 2 is the marginal source of supply and sets the clearing price in City 3. This leads to higher prices for Mine 1 everywhere it sells coal and an economic rent above its costs. A drop in demand in City 3 eliminates its demand from Mine 2. Mine 1 then loses its rent and prices fall in all locations. As wind reduces coal demand, high-cost mines stop producing and rents for lower-cost mines drop in all of the provinces they serve, increasing the required subsidy for wind investment. That coal prices can fall significantly without a decrease in production implies that other policy measures, besides the extensive development of renewables, have to be implemented in order to significantly reduce coal use in power generation.

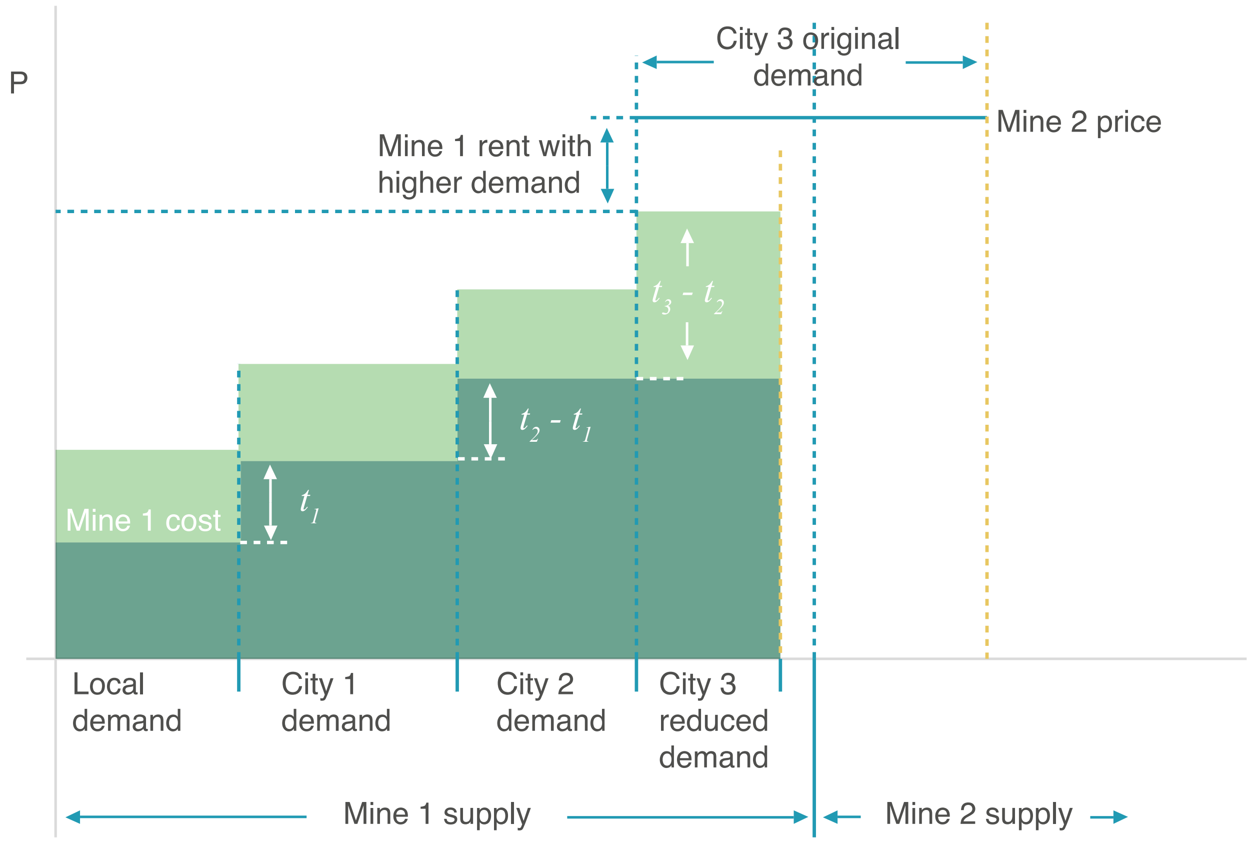

Figure 4. How a small quantity change can lead to a large change in average prices of delivered coal.

Conclusion

The state of the Chinese power sector exemplifies the transaction costs and market inefficiencies that can occur during a partial deregulation within a complex economic system. China's past reforms have moved its electricity sector to the middle ground between fully functioning markets and a command system. That middle ground means there are fewer ways for government or market to ameliorate problems and makes the market more brittle and less equipped to adjust to unforeseen events.

By eliminating the caps, the generation mix improves and costs drop. The 29 billion RMB in annual subsidies are no longer necessary. Deregulation also facilitates development of cost-effective renewables policies, since the baseline costs and carbon levels are altered by the caps and the utilities are better able to provide backup to intermittent technologies.

Eliminating the caps reduces the advantages of market concentration by the generators and thereby lowers the barriers to entry for new participants, expanding competition. The need for vertical integration to control fuel costs is reduced as well. Furthermore, eliminating the tariff caps expands interregional power trade helping unify the country's power market.

Usually, adding a non-dispatchable technology like wind complicates the operations of the electricity sector and adds to rigidities. However, wind has the opposite effect on the problems created by price caps. By reducing the demand for coal, added wind capacity lowers the price of coal, loosens the revenue constraint and lessens the distortions caused by the caps. Thus, the level of the subsidies resulting from the feed-in tariffs is increased because of the efficiency improvements from relaxing the caps.

The expansion of China's capacity to move coal and the resulting lower costs of delivered coal has made coal-fired generation extremely competitive. As a result, neither restrictive tariff caps on coal-fired generation, nor the increase in the share of renewables have had a significant effect on total generation with coal. A substantial reduction in coal use in China's energy system would require different policy approaches.

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Appendix 1: Mathematical Formulation of China's Electricity Sector

Table A.1. Indices, variables and constants.

Indices	$i;\ i^{n};\ i^{w}$	Capacity type; Spinning reserve; Wind
	$r,\ r'$	Region
	$l;\ l';p$	Load segment; Peak load segment
	j	Wind capacity increment
	$f;\ f^{a};\ f^{o}$	Fuels; Coal; Other fuels (oil, gas, uranium)
	k	Fuel supply step (only f^{o})
	$c;s$	Calorific value; Sulfur content (*coal only*)
Variables	$x_{i,\ l,\ r}$	Amount of capacity generating in load segment l in MW
	$y_{i^{n},\ l,\ r}$	Amount of capacity used for spinning reserves in MW
	$z_{i,r}$	New capacity built
	$t_{l,r,r'}$	Electricity transmission in MWh
	$u_{r,r'}$	New transmission capacity
	$\theta_{i^{w},n,r}$	Level of wind operation
	$\upsilon_{i,\ f,\ c,\ s,\ k,\ r,}\ ;\ \upsilon_{i,\ f^{o},\ k,\ r}$	Fuel consumption coal and other fuels
	$q_{i^{w},r}$	Subsidy for wind generators
	$\pi_{f,\ c,\ s,\ r}$	Fuel price
Constants	$S_{i,r}$	Allowed generators' financial losses (including subsidies)
	$\upsilon_{f^{c},\ c,\ s,\ r}$	Non-power coal consumption
	$E_{i,r}\ ;\ Etr_{r,r'}$	Existing capacities: generation; transmission
	$D_{l,r}\ ;H_{l}$	Power demand in MWh; hours in load segment
	G_{i}	Internal electricity use coefficient
	$Y_{r,r'}$	Transmission yield
	$T_{l,l',r,r'}$	Mapping coefficient between load segments of different regions
	$\hat{p}_{i,r}$	On-grid tariff caps
	$OM_{i};\ Ot_{,r,r'}$	O&M costs: generation; transmission
	$K_{i};\ Kt_{,r,r'}$	Annualized capital and fixed costs: generation; transmission
	C_{c}	Conversion to Standard Coal Equivalent
	$F_{i,f,r}$	Power plant heat rate
	$B_{f,k,r}$	Bound on step k for fuel
	a	Spinning reserves requirement as fraction of wind capacity
	b	Fraction of fuel and variable costs consumed by spinning reserves
	I_{j}	Size of wind capacity increments in MW
	$\Delta_{j,l,r}$	Reduction in load in segment l for each wind increment
	W	Capacity target in the wind policy
	DW_{t}	Dry weight of sulfur
	$EC_{i}^{SO_2}\ ;EC_{i}^{NOx}$	Coefficients for emissions control: SO_2 ; NOx
	$N_{i,c,r}$	NOx emissions per unit of coal consumed
	$T_{r}^{SO_2}\ ;T_{r}^{NOx}$	Total emissions limit: SO_2 , NOx

Since the focus of the paper is on the electricity market, here we detail just the representation of China's electricity sector, which means for the model to be complete, the objective function contains a cost term for the coal that is delivered to utilities. In a combined coal and utilities model this term would be removed and replaced by coal material balances in the constraints that feed coal to utilities. A description of the coal supply model is presented in Rioux et al. (2015).

The electricity sector is formulated as a Stackelberg game, where every regional utility acts as a leader that minimizes the total cost of supplying and transmitting power subject to the caps limiting on-grid tariffs. The model minimizes the total cost across all the regions simultaneously. This means each utility minimizes its costs and trades electricity with the other utilities at prices set to marginal costs.

We first present the model under the Long-run Deregulation scenario because it can be formulated as a linear program both standalone and combined with the coal model. We then add the constraint that captures the consequences of the price caps, explaining why this change requires an MCP formulation in the integrated model. The mathematical program for the deregulation policy is:

$$min \sum_{i,l,r} OM_i \cdot (\boldsymbol{x}_{i,l,r} + b \cdot \boldsymbol{y}_{i^n,l,r}) \cdot H_l + \sum\nolimits_{i^n,r} K_{i^n} \cdot \boldsymbol{z}_{i^n,r}$$

$$+ \sum\nolimits_{i,f,c,s,k,r} \boldsymbol{\pi}_{f,c,s,r} \cdot \boldsymbol{v}_{i,f,c,s,k,r}$$

$$+ \sum\nolimits_{r,r'} Kt_{r,r'} \boldsymbol{u}_{r,r'} + \sum\nolimits_{l,r,r'} Ot_{r,r'} \boldsymbol{t}_{l,r,r'} - \sum\nolimits_{i^w,r} \boldsymbol{q}_{i^w,r}$$

Subject to the following constraints:

Fuel material balances:

$$\sum\nolimits_{(c,s,k)} \boldsymbol{v}_{i,f,c,s,k,r} \cdot C_c - \sum\nolimits_l F_{i,f,r} \cdot H_l \cdot (\boldsymbol{x}_{i,l,r} + b \cdot \boldsymbol{y}_{i^n,l,r}) \geq 0 \qquad \text{(A.1)}$$

Supply constraints for fuel other than coal:

$$\sum\nolimits_i \boldsymbol{v}_{i,f^o,k,r} \leq B_{f^o,k,r} \qquad \text{(A.2)}$$

Capacity limits for power generation and transmission:

$$\boldsymbol{z}_{i,r} - \boldsymbol{y}_{i^n,l,r} - \boldsymbol{x}_{i,l,r} \geq -E_{i,r} \qquad i \neq i^w \qquad \text{(A.3)}$$

$$\boldsymbol{u}_{r,r'} - \sum\nolimits_l \boldsymbol{t}_{l,r,r'} \geq -Et_{r,r'} \qquad \text{(A.4)}$$

Power transmitted constrained by the amount produced:

$$\sum\nolimits_i H_l \cdot G_i \cdot \boldsymbol{x}_{i,l,r} - \sum\nolimits_{r'} \boldsymbol{t}_{l,r,r'} \geq 0 \qquad \text{(A.5)}$$

Power demand:

$$\sum\nolimits_{r',l'} Y_{r',r} \cdot T_{l',l,r',r} \cdot \boldsymbol{t}_{l',r',r} \geq D_{l,r} \qquad \text{(A.6)}$$

Reserve margin:

$$\sum_{i \neq i^w} (\boldsymbol{z}_{i,r} + E_{i,r}) \geq 1.1 \cdot D_{p,r} \qquad \text{(A.7)}$$

Wind operation:

$$\boldsymbol{z}_{i^w,r} - \sum\nolimits_n I_n \cdot \boldsymbol{\theta}_{i^w,j,r} \geq -E_{i^w,r} \qquad \text{(A.8)}$$

$$\sum\nolimits_{i^w} \boldsymbol{\theta}_{i^w,j,r} \leq 1 \qquad \text{(A.9)}$$

$$\sum\nolimits_{\boldsymbol{n}} \Delta_{j,l,r} \cdot I_j \cdot \boldsymbol{\theta}_{i^w,j,r} - \boldsymbol{x}_{i^w,l,r} \geq 0 \qquad \text{(A.10)}$$

Added spinning reserve requirement for wind power:

$$\sum\nolimits_{i^n} \boldsymbol{y}_{i^n,s,r} - \sum\nolimits_{i^w,j} a \cdot \Delta_{j,l,r} \cdot \boldsymbol{\theta}_{i^w,j,r} \geq 0 \qquad \text{(A.11)}$$

Meeting the wind capacity target:

$$\sum_r z_{i^w r} \geq W - \sum_r E_{i^w r} \qquad \text{(A.12)}$$

Regional sulfur emissions:

$$\sum_{(c,s)}\left(\sum\nolimits_{i,f^a} \boldsymbol{v}_{i,f^a,c,s,k,r} \cdot EC_i^{SO_2} + \tilde{v}_{c,s,r}\right) \cdot DW_s \cdot 1.6 \leq T_r^{SO_2}$$

(A.13)

Nitrous oxide emissions:

$$\sum\nolimits_{i,f^a,c}\left(\boldsymbol{v}_{i,f^a,c,s,k,r} \cdot N_{i,c,r} \cdot EC_i^{NO_x}\right) \leq T_r^{NOx}$$

(A.14)

$$y_{i^n(i),l,r} > 0,\ x_{i,l,r} \geq 0,\ q_{i^w(i),r} \geq 0,\ u_{r,r'} \geq 0,\ t_{l,r,r'} \geq 0$$

(A.15)

Note that the transmission variables between regions r' and r, $T_{l',l,r',r'}$ link different load segments, with the electricity produced in one load segment in one region distributed over multiple load segments in another region. This allows the model to match the same times in the load duration curves of the different regions and capture the effects of non-coincident peaks in the value of generation and transmission.

In the standalone electricity model the $\pi_{f,\,c,\,s,\,r}$ for coal are constants, making the model a linear program. In the integrated model we combine the objective functions of the two models and we remove the term $\pi_{f,\,c,\,s,} \cdot v_{i,\,f,\,c,\,s,k,r}$ for coal from the objective function. We add material balance constraints that link the coal model to the utilities model and the price of coal comes from the dual variables of these constraints.

We now add the profitability constraint that measures the effects of the price caps in the regulated case. Adding this constraint to the integrated coal and utilities model means there is no corresponding optimization problem to the MCP.

For coal we redefine $\pi_{f,\,c,\,s,\,r}$ to be the set of dual variables associated with the material balances constraints that link the coal transportation network to the utility model. The profitability constraint requires that the generators in a region be profitable over all of their equipment and allows them to lose money on some plants as long as they make it up on others.

$$\sum\nolimits_i\left[\left(\hat{P}_{i,r} \cdot G_{i,r} - OM_i\right)\left(\sum\nolimits_l H_l \cdot \boldsymbol{x}_{i,l,r}\right) - \sum\nolimits_{f,c,s} \boldsymbol{\pi}_{f,c,s,r} \cdot \boldsymbol{v}_{i,f,c,s,r} + S_{i,r}\right]$$
$$- \sum\nolimits_{i^n,l} OM_{i^n} \cdot b \cdot W_s \cdot \boldsymbol{y}_{i^n l,r} - \sum\nolimits_i K_i \cdot \left(\boldsymbol{z}_{i,r} + E_{i,r}\right) \geq 0$$

(A.16)

The first term is what the revenues would be at the price caps less the operating and maintenance costs, the second is the fuel costs, the fourth is the operating and maintenance costs for the spinning reserve and the fifth is the annualized cost of capacity. The second term, $\pi_{f,\,c,\,s,} \cdot v_{i,\,f,\,c,\,s,k,r}$, is the product of a primal and dual variable, which can appear in an MCP but not in an optimization model.

The third term in (A.16) is a subsidy that is added as a constant to make this constraint feasible, as generators received government subsidies and reported financial losses in 2012. We found that this constraint cannot be met without a subsidy, given the shape of the load duration curve and the requirement to have spinning reserves to back up the wind generators. We iterate to find the smallest subsidy necessary for the model to be feasible. That is, we have a mathematical program subject to equilibrium constraints where the government is minimizing the subsidy needed to make generators profitable subject to the market equilibrium.

Appendix 2: Model Calibration

The model, calibrated to 2012 data (Rioux et al.'s (2015) model was also recalibrated to the 2012 data), contains 12 regions, aggregating adjacent provinces with similar cost structures, on-grid tariff caps and shared grid resources. A total of 21 coal supply nodes are used to capture the geographic dispersion of resources. Every regional load curve is split into five load segments. Since demand is represented by a load duration curve, only one non-dispatchable renewable generator can be included. We selected wind, by far the largest source of non-dispatchable power in 2012.

Regional power producers have 10 different generator types (14 when considering emission controls). Transmission capacities are split into High Voltage Alternating Current (AC) and Direct Current (DC) interregional transmission lines. Data sources are listed in table A.2.

Table A.2. Power sector model calibration data.

Data	Sources
Power demand (data used to construct load curves)	Li et al. (2007), Atong et al. (2012), Wei et al. (2010), Wang et al. (2013), Yang (2009), Ma et al. (2011), Cheng et al. (2013), Bai and Li (2010), Hou (2007), Cheng (2007), Liu et al. (2009), Yu et al. (2011), IHS (2014).
Existing generation capacities	Platts (2015),IHS (2015)
Fuel demand	NBS (2013), CEIC (2016)
Fuel prices	NDRC
Capital discount rate	Dong (2012)
Power plant capital costs and gross thermal efficiencies	IEA WEIO (2014)
Power plant fixed and variable costs	IEA WEIO (2014), WEC (2010)
SO_2 and NOx emission factors	Schreifels et al. (2012)
Regional SO_2 and NOx emissions	MEP (2013)
Capital and variable cost of SO_2 (FGD) and NOx (SCR) controls	Zhang (2006)
NOx flue gas concentration range	Zevenhoven and Kilpinen (2001)
On-grid tariff caps, tariff levels, SO2 and NOx tariff supplements	NDRC, China Resource Power Holdings (2012)
Existing and planned power transmission capacities	NEA (2015), NDRC (2015), SASAC, China Resource Power Holdings (2012), Jineng Group (2014), People's Daily (2014)
Transmission costs	Cheng (2015)
Interregional and intraregional transmission losses UHV-DC and HV-AC	IEA ETSAP (2014), The World Bank (2016), China Southern Power Grid (2013), Cheng (2015)
Capital cost, UHV-DC and HV-AC	State Grid Corporation of China (2013), SASAC (2007), Zhang (2014), Yang and Gao (2015), Paulson Institute (2015)
On-grid tariffs	NDRC (2011)
Regional wind resources and profiles	He et al. (2014), Yu et al. (2011)

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About the Project

The KAPSARC Energy Model of China (KEM China) project began in 2014 to study energy and environmental issues in China. KEM China has been developed to understand China's energy economy and fuel mix, how they are impacted by government intervention, as well as their interaction with global markets. It is a modular integrated mixed-complementarity problem model that optimizes supply decisions, minimizing fuel and technology costs, while taking into account the effect of government regulation on prices and the environment.

Notes

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