Berkeley-Tsinghua Joint Research Center Working Paper 004

Challenges and Strategies for Electricity Market Transition in China

Authors:

Jiang Lin[1,2], Fredrich Kahrl[3], Jiahai Yuan[4], Liu Xu[1], Weirong Zhang[4]

[1] Lawrence Berkeley National Laboratory
[2] University of Calfiornia, Berkeley
[3] Energy + Environmental Economics (E3)
[4] North China Electric Power University

Janaury 2019

Acknowledgements

This work was supported by the William and Flora Hewlett Foundation and the MJS Foundation, through the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

This is a working paper, therefore intended to facilitate discussion on research in progress. This paper represents the opinions of the authors, and not meant to represent the position or opinions of the authors' institutions. Any errors are the fault of the authors. Working papers published under this Series may subsequently be published elsewhere.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

Challenges and Strategies for Electricity Market Transition in China

Jiang Lin[1,2], Fredrich Kahrl[3], Jiahai Yuan[4], Liu Xu[1], Weirong Zhang[4]

[1] Lawrence Berkeley National Laboratory; [2] University of Calfiornia, Berkeley; [3] Energy and Environmental Economics (E3); [4] North China Electric Power University

Abstract

China is currently pursuing electricity reforms that would create wholesale markets for electricity. Electricity markets hold considerable promise for facilitating China's transition to clean energy systems. However, transition obstacles have the potential to frustrate market reforms. The most important of these obstacles is the financial impact of market reforms on coal generation, which accounts for most of China's electricity generating capacity. In this paper, we examine the impact of market reforms on coal generation in China, using a case study of Guangdong Province. We find that market prices are likely to lead to significant decreases in net revenues for coal generators relative to the current benchmark tariff, with 40% to 60% of coal generation capacity unable to cover the cost of remaining in commercial operation. We estimate that existing coal generators in Guangdong had 94 billion yuan (US$14 billion) in outstanding debt in 2016, creating large risks for banks and raising questions about the potential impacts of electricity market reforms on China's financial industry. The impact of market reforms on coal generators creates two problems—transition and resource adequacy—that may have a common solution. We argue that dealing with transition issues through the development of long-term resource adequacy mechanisms presents a better balance between consumer savings and easing generator financial impacts from electricity market reforms than making transition payments to coal generators.

This paper assesses the financial impacts of electricity market transition on coal generators in Guangdong Province, based on an analysis of their expected market revenues and costs. The paper is organized into four sections. Section 1 (*Background: The Allocation and Reallocation of Generation Cost Risks in China's Electricity Industry*) provides an overview of how the risks associated with generation costs were historically allocated and how they are likely to be reallocated in a competitive electricity market. Section 2 (*Methods*) summarizes the methods used in our analysis. Section 3 (*Results*) presents the results. Section 4 (*Conclusions and Discussion*) examines the implications for how policymakers in China should manage the transition to electricity markets.

Background: The Allocation and Reallocation of Generation Cost Risks in China's Electricity Industry

Electricity markets will lead to significant changes in the allocation of risk across electricity generators, buyers, and customers in China. This section provides an overview of historical approaches to setting generation tariffs in China and how electricity markets will reallocate that risk. The focus in this section is on coal-fired generation.

Generation Tariffs in China, 1985-2018

In 1985, facing power shortages, China's central government opened generation investment and ownership to new, non-utility actors: provincial government-owned companies, foreign companies, and domestic private companies. The emergence of non-utility generators required a means to compensate them, which was achieved through wholesale generation tariffs. The first of these tariffs ("cost plus tariff" in Table 1.) was developed in 1985. Restructuring in 2002 increased the importance of wholesale generation tariffs, as the national State Power Corporation was split into separate generation and grid companies.

In the 1990s and 2000s, successive rounds of revisions to wholesale generation tariffs sought to enable full cost recovery for generators while providing stronger incentives for cost reductions. Table 1 provides a summary of generation pricing in China since 1985, focusing on coal generation tariffs.[1]

Table 1. Coal Generation Tariffs in China, 1985-Present

Generation Pricing Approach		Years	Description
Cost-plus tariff	还本付息电价	1985-1998	Paid generators on a levelized energy cost (yuan/kWh) basis using actual annual costs, calculated individually for each plant and, in some cases, each unit; tariffs were initially high, reflecting higher depreciation costs, and then dropped significantly once the plant or unit was fully depreciated, resulting in "tariff shocks"
Operating life tariff	经营期电价	1998-2002	Paid generators on a levelized energy cost (yuan/kWh) basis, calculated individually for each plant using average cost across the expected lifetime of the plant; addressed the "tariff shock" problem with the cost-plus tariff

[1] For overviews of electricity pricing reforms in China, see [9] [10] [11] [12] [15] [16].

Generation Pricing Approach		Years	Description
Benchmark tariff	标杆上网电价	2004-present	Pays generators on a fixed benchmark energy cost (yuan/kWh) basis, with a nearly uniform tariff for all coal generators using a benchmark based on the estimated levelized cost of an advanced coal unit
Market-based pricing	市场定价	2015-present	Generation prices are negotiated bilaterally between generators and buyers or cleared through a monthly auction; initially generation prices were based on reductions from the benchmark tariff; some provinces began market-based pricing for coal generation before 2015 and some coal generators continue to be paid through the benchmark tariff

Historically, generation tariffs in China faced two main interrelated challenges: (1) managing fuel—mostly coal—price volatility, given the political sensitivity around raising retail electricity prices; and (2) balancing incentives for generator availability and investment cost recovery.

China's generation tariffs were set on an energy (yuan/kWh) basis, which meant that generator revenues and profits were tied to their operating hours. To ensure fair allocation of these hours, in the early 2000s government agencies developed an annual planning process to set generator operating hours, based on a principle of "equal allocation for similar technologies."[2] If generation capacity was scarce, average operating hours would increase and generators would earn above-average net revenues. If generation capacity was in excess, average operating hours would decrease and generators would earn below-average net revenues.

Political difficulties in raising retail electricity prices meant that pricing bureaus adjusted the benchmark tariff on an infrequent basis and tariff changes were only loosely tied to changes in coal prices. When coal prices were rising and pricing bureaus did not promptly adjust tariffs, generators absorbed the fuel cost increase, reducing their net revenues. When coal prices were falling and pricing bureaus did not promptly adjust tariffs, generators retained the increase in net revenues.

The electricity reform process initiated in 2015 aims to replace both the wholesale generation tariff and the mechanism for passing through fuel cost changes with market-determined pricing.[3] To facilitate this transition, the central government began to allow larger industrial customers and competitive retail providers to contract directly with coal generators for energy. From 2015 to 2018, government agencies gradually reduced the number of planned hours allocated to coal generators, forcing them to rely on market transactions for an increasing share of their energy sales. At the same time, government agencies began to allow larger industrial customers to procure their energy either directly from generators or through a competitive provider.

This "medium- and long-term market" (中长期市场) includes two primary trading options: (1) one-year bilateral contracts for energy (MWh) signed between generators and load serving entities (LSEs); (2)

[2] State Electricity Regulatory Commission. 2004."Interim Measures on Promoting Openness, Fairness and Fairness in Power Dispatching" (in Chinese).《关于促进电力调度公开、公平、公正的暂行办法》

[3] State Council. 2015. "Several Opinions on Further Deepening the Reform of the Power System" (in Chinese).《关于进一步深化电力体制改革的若干意见》

monthly centralized auctions for energy (MWh) organized by a power exchange.[4] The monthly auctions are cleared using a uniform market clearing price. In late 2018, Guangdong became the first province to announce detailed rules for an electricity spot market, which will include day-ahead and real-time markets.[5]

Generation Cost Recovery in a Market Environment

The transition toward market pricing will have a significant impact on generation cost recovery and the allocation of risks between sellers (mostly generators) and buyers (mostly large customers and retail providers).

In a competitive market environment, generators recover their investment and other fixed costs through net revenues: revenues minus short-run operating costs [1] [2]. In long-term bilateral contracts, these net revenues are the result of negotiations between buyers and sellers. For instance, if a buyer and seller negotiate a contract for 350 yuan/MWh ($51/MWh) and the seller has an average short-run operating cost of 300 yuan/MWh, the seller will earn net revenues of 50 yuan for each MWh sold to the buyer. Contract prices are driven by supply and demand. In markets that are oversupplied, buyers will be able to drive down contract prices to levels close to the minimum level that generators need to remain in commercial operation ("going forward costs"). In markets where supply is tight, sellers will be able to drive up contract prices to levels close to or even exceeding the cost of new entry for a new generating unit.

In organized markets with uniform market clearing prices (monthly and spot markets in China), generators' net revenues are the difference between the market clearing price and their short-run operating cost. If markets are competitive, generators will bid their expected short-run marginal cost in these shorter-term, uniform clearing price markets, to avoid the potential downside of not being dispatched.

In markets with well-developed forward markets (e.g., bilateral contracting, monthly auctions) and spot markets, prices will tend to converge toward spot market pricing, as market participants can arbitrage between forward and spot markets over time.[6] If spot market prices are low, buyers will tend to be reluctant to sign long-term contracts. If spot market prices are high, sellers will tend to be reluctant to sign long-term contracts [3]. As in all markets, the equilibrium between these competing forces is shaped by the balance between greed and fear. In electricity markets, this equilibrium is often shaped by regulations around resource adequacy that aim to ensure adequate generation resources [4] [5] [6].

Market pricing will tend to reduce fuel price risk for generators, as they can pass through fuel price changes to LSEs through a combination of fuel price indices in bilateral contracts and spot market pricing. However, a central tenet of wholesale electricity markets is that generators take on some, and in some cases a significant amount of, fixed cost recovery risk.

---

[4] South China Energy Regulatory Office of National Energy Administration. 2018. "Implementation Rules for Medium- and Long-Term Transaction in the Guangdong Electric Power Market (Draft for Comments)" (in Chinese). 《广东电力市场中长期交易实施细则》

[5] South China Energy Regulatory Office of National Energy Administration. 2018. "A Series of Rules for the Power Spot Market in South China (Draft for comments)" (in Chinese).《关于征求南方（以广东起步）电力现货市场系列规则》

[6] This is not to suggest that forward prices will converge *to* spot market prices. For a variety of reasons, wholesale electricity market prices in the United States have historically had a forward premium [13] [14].

In China, a key challenge for the transition to electricity markets is that the majority of the country's electricity generation capacity consists of large, efficient baseload coal units that were built within the last decade-and-a-half. When supply exceeds demand, as it currently does in some parts of the country, average spot market prices will tend to fall to the short-run operating cost of a relatively efficient mid-merit coal unit, which may make it difficult for coal generators to recover their fixed costs. As a result, negotiations around stranded costs may become critical to the electricity reform process.

Stranded Costs and Electricity Market Transition: International Experience

Questions around stranded costs were a central theme in the transition to competitive electricity markets in most countries, but philosophies on allowing stranded cost recovery and mechanisms for recovering stranded costs differed significantly both among and within countries, due to differences in generation characteristics and regulatory cultures.

'Stranded cost' is typically defined as the difference between the regulated book value[7] and market value of an individual asset or multiple assets, if the value of these assets is lower—and thus some approved costs and investment returns are unrecoverable—in a competitive market than under regulation [7] [8] [9] [10] [11]. The existence of stranded costs presupposes regulated costs and returns, though performance-based cost mechanisms have often been considered a form of "regulated costs" [8].

This simple definition belies the complexity of defining, measuring, and efficiently and equitably recovering stranded costs. Successful navigation of these issues is critical to market transition. The collapse of California's electricity market in 2001 was due, in part, to the failure of regulators to understand and anticipate the tradeoffs and risks in different approaches to stranded cost recovery [8].

From a regulatory perspective, stranded cost recovery requires two determinations: (1) to what extent should companies be allowed to recover stranded costs; and (2) if companies are allowed to recover stranded costs, how should these costs be recovered [12]?

In the United States, a polemical literature developed around the first question. Proponents of allowing utilities to recover stranded costs argued that utility investments and contracts were undertaken in good faith, were deemed prudent and approved by regulators, and were part of utilities' obligation to serve all customers [13]. Opponents argued that utilities should have made investments and negotiated contracts that were consistent with market outcomes, and thus that allowing them to recover stranded costs would be societally inefficient [14]. A third view argued that stranded cost recovery was inefficient but allowing at least some recovery of stranded costs might be necessary to build broad support for reforms [15] [16].

Table 2 provides a more general summary of arguments for and against allowing stranded cost recovery.

[7] Regulated book value is the value of an asset on a company's books, as determined by regulatory accounting rules or regulatory incentive mechanisms.

Table 2. Arguments for and Against Allowing Regulated Incumbents to Recover Stranded Costs

Supporting Arguments [17] [18]	**Opposing Arguments** [19] [20] [21]
Incumbents' investments and contracts were undertaken in good faith and approved for full cost recovery by regulators, in a form of implicit contracting governed by a regulatory compact	Incumbents should have internalized the market risks in their investment and procurement decisions, particularly since they knew deregulation was imminent; the regulatory compact has no legal basis
Disallowing incumbents to recover regulated costs and investment returns is a form of asset confiscation by the state	Governments do not guarantee regulated providers that their industries will never be deregulated; governments have no legal obligation to compensate incumbents
Forcing regulated incumbents to absorb above-market costs will increase their long-run cost of capital, affecting their ability to make continued investments; incumbents' approved cost of capital does not compensate them for regulatory risks	The financial markets have appropriately compensated incumbents for the widely-known risk that the industry could be deregulated; the markets will continue to provide appropriate risk-adjusted returns to incumbents
Disallowing incumbents to recover above-market costs does not increase productive efficiency and reduces allocative efficiency by shifting costs among consumers	Allowing stranded cost recovery decreases dynamic efficiency by slowing new entry, delaying or preventing competition, and reducing the benefits of market reforms for consumers; poorly designed stranded cost mechanisms can reduce productive and allocative efficiency

In practice, regulators in the United States, the UK, Spain, and some other parts of Europe allowed incumbent providers to recover most or all of their above-market costs as part of the transition to electricity markets. In the United States, these costs were primarily associated with above-market contracts with independent power producers that were mandated by the federal government's Public Utilities Regulatory Policy Act (PURPA) and, to a lesser extent, with utility-owned high cost nuclear facilities. In the UK, stranded costs were primarily associated with publicly-owned nuclear facilities. In the United States, the decision to allow stranded cost recovery was a regulatory decision rather than a legal one. Even at the federal level, there was never a legal basis for compensating incumbent providers for stranded costs.

The primary challenge to measuring stranded costs is that electricity market prices, and some generation costs (e.g., nuclear decommissioning costs), are not known in advance. Baxter and Hirst [22] describe three methodological dimensions along which stranded costs are typically assessed: (1) administrative versus market, or whether the value of incumbents' assets is determined by public agencies or market participants; (2) ex ante versus ex post, or whether stranded costs are assessed before or after market prices are known; (3) bottom-up versus top-down, or whether stranded costs are determined on the basis of a detailed calculation of asset-specific costs or a high-level portfolio-wide metric. In practice, regulators in the United States used a combination of divestment (market valuation), ex ante valuation and ex post adjustment, and top-down settlement with bottom-up verification and reconciliation.

The design of mechanisms for stranded cost recovery can have a significant impact on market outcomes. To guide the design of such mechanisms, Tye and Graves [23] described several criteria: "reliable cost recovery, competitive neutrality, allocative efficiency, fairness of incidence on customers, transparency and predictability, administrative simplicity, objectivity, automatic termination, and incentives to

mitigate." In principle, U.S. regulators accepted that stranded cost recovery mechanisms should seek to minimize distortions on market prices and transactions, should be non-bypassable, and should limit cost recovery to a short, fixed period [24].

In practice, there was a diversity of designs for stranded cost recovery mechanisms, ranging from California's "headroom charge" (difference between market prices and frozen retail rate), to volumetric surcharges on loads, to fixed surcharges on loads via transmission or customer charges [8]. Woo et al. [8] argue that fixed charges based on historical consumption provide the best balance among collection certainty, efficiency, and equity.

Issues around stranded costs in China's transition to electricity markets differ from that in the United States and Europe, in three respects: (1) generation assets have already been transferred to separate generating companies; (2) the vast majority of these generation assets are owned by state-owned enterprises (SOEs) and privatization of these assets is unlikely; (3) grid companies, which have historically been the only load serving entities in China, did not have long-term contractual liabilities with generators.

These differences suggest that, to a larger extent than in the United States and Europe, a threshold question for Chinese regulators will be whether the financial impact of market reforms on state-owned generating companies should be cushioned by allowing them to recover some or all of the investment costs that are stranded in the transition to markets. If the answer is "yes," a key question for Chinese regulators is mechanism design and "who pays": how the costs are spread across state-owned banks, other state-owned enterprises, and different classes of electricity consumers.

As in the United States [25] and Europe [26], the transition to a low-carbon electricity sector will also have implications for the potential for stranded assets—in particular coal-fired generating assets—in China's electricity sector. The transition to electricity markets complicates stranded cost considerations related to environmental policy, because in principle generators should be shouldering more investment risk.

Methods

This methods section focuses on analytics and definitions. The supplementary materials contain a detailed description of data inputs and sources.

Our database of coal plants in Guangdong includes 173 units with 63,890 MW of installed capacity. To calculate net revenues by generator, we categorize these 173 plants into 6 bins in terms of their installed capacity and initial year of commercial operation. We assign average gross revenues and net revenues to each generator type based on the results of a market dispatch model described in [7], where net revenues for generator type i (NR_i) are equal to gross revenues (GR_i) minus short-run operating costs (OC_i).

$$NR_i = GR_i - OC_i$$

Short-run operating costs include fuel and variable operations and maintenance (O&M) costs.

We use three price scenarios: (1) *Low Market Price*, which has low coal prices (800 yuan/tce) and a high hydro year (3,550 fully loaded operating hours for hydropower); (2) *High Market Price*, which has high

coal prices (1,000 yuan/tce) and a low hydro year (2,096 operating hours, based on 2015 actual); and (3) *Benchmark*, based on the 2016 benchmark tariff (0.4505 yuan/kWh) and 2016 operating hours (3,932 hrs/yr).

Our projected average market prices in the Low Market Price and High Market Price scenarios are 302 yuan/MWh (US$44/MWh) and 371 yuan/MWh (US$54/MWh), respectively. These prices correspond to the marginal cost of a medium-efficiency (330-340 kgce/MWh) coal unit. Table 3 shows projected gross and net revenues by generator type and price scenario, based on these market prices and the benchmark tariff.

Table 3. Projected Generator Gross and Net Revenues by Generator Type and Price Scenario

			Low Market Price Scenario Revenues (yuan/kW-yr)		High Market Price Scenario Revenues (yuan/kW-yr)		Benchmark Scenario Revenues (yuan/kW-yr)	
Type	ICAP Range (MW)	COD Range	Gross	Net	Gross	Net	Gross	Net
1	≥ 1000	1980-2017	2,060	293	2,544	380	1,771	771
2	600-999	2010-2017	2,053	196	2,593	258	1,771	707
3	600-999	1980-2009	1,558	122	2,071	162	1,771	664
4	300-599	2000-2017	1,001	99	1,383	128	1,771	630
5	300-599	1980-1999	554	68	839	84	1,771	592
6	0-299	1980-2017	288	62	524	70	1,771	553

Generator annual fixed costs consist of labor, fixed maintenance, insurance, annual debt service, and tax costs. Generators are generally required to pay labor, insurance, fixed maintenance, and taxes to reman in commercial operation. We refer to these costs as "going forward fixed costs."

To assign labor, insurance, and fixed maintenance costs ("fixed O&M costs") to generators, we classify generators into six categories based on their installed capacity. For data availability reasons, these six categories are different than the six categories for assigning gross and net revenues. Fixed O&M costs for generator type j (FO_j) are the sum of labor (LA_j), insurance (IN_j), and fixed maintenance costs (FM_j).

$$FO_j = LA_j + IN_j + FM_j$$

Non-income taxes include operating, other, and value added taxes. "Other" is a residual category that includes urban construction, property, land use, and education taxes. Operating and other taxes are assessed on gross revenues. Value added tax is assessed on labor and capital value added.

Going forward fixed costs (GF_{ij}) are the sum of fixed O&M costs (FO_j), operating and other taxes (OT_i), and value added taxes (VT_{ij}).

$$GF_{ij} = FO_j + OT_i + VT_{ij}$$

Operating profit (OP_{ij}) is the amount remaining after generators have paid annual fixed O&M and taxes, or net revenues minus going forward fixed costs.

$$OP_{ij} = NR_i - GF_{ij}$$

To assign capital costs to generators, we classify generators into five categories based on technology (ultra-supercritical, supercritical, subcritical), installed capacity, and initial year of commercial operation. Again, this classification (generator type k) is different than that for revenues or fixed O&M costs. We match depreciation periods, debt share, debt interest, and loan repayment periods to generators based on their initial year of commercial operation.

Income tax (IT_{ijk}) is assessed at the income tax rate (t) on operating profits minus annual depreciation (AD_k) and debt interest payments (DI_k).

$$IT_{ijk} = t \times \left(OP_{ij} - AD_k - DI_k\right)$$

For simplicity, we assume straight-line depreciation with matching depreciating and loan periods.

Generator net income (NI_{ijk}) is defined as net revenues (NR_i) minus fixed O&M costs (FO_j), operating and other taxes (OT_i), value added taxes (VT_{ij}), annual debt principal payments (DP_k), debt interest payments (DI_k), and income tax (IT_{ijk}).

$$NI_{ijk} = NR_i - FO_j - OT_i - VT_{ij} - DP_k - DI_k - IT_{ijk}$$

Results

Characteristics and Ownership of Guangdong's Coal Generation Fleet

On average, Guangdong's coal generation fleet is large, efficient, and new. Coal-fired units accounted for 61% of Guangdong's within-province installed generation capacity and 58% of its within-province electricity generation in 2016. Large (≥ 600 MW) units make up just over 60% of Guangdong's coal generation fleet (Figure 1a) and three quarters of these large units use ultra-supercritical or supercritical technologies. Mid-size (300-350 MW) units account for most of the remainder (Figure 1a).

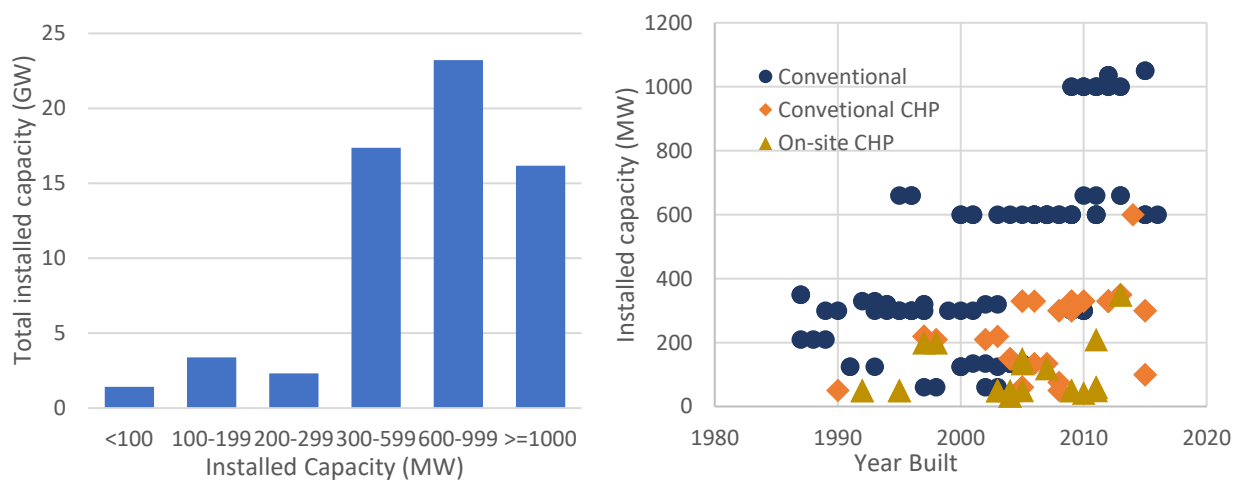

Figure 1. Installed Capacity of Guangdong's Coal Fleet by Plant Size, Year Built, and Type

About half of Guangdong's small- to mid-size coal generation capacity (≤ 350 MW) consists of combined heat and power (CHP) units. Many smaller (< 200 MW) units are on-site CHP. Nearly 70% of Guangdong's coal generation capacity was built after 2005 (Figure 1b).

Guangdong's coal generation fleet is owned by 30 companies, with 92% of total capacity owned by 17 state-owned companies and most of this state-owned capacity majority-owned by local companies. Twelve of the 30 companies are privately owned, accounting for 7.6% of total capacity. The remaining units are owned by one international company. Figure 2 shows the 12 largest companies in terms of installed capacity, representing 90% of installed coal capacity.

As Figure 2 shows, coal generation ownership in Guangdong is relatively concentrated. The largest plant owner, Guangdong Yudean Group, owns 52 units with 22,375 MW of installed capacity, accounting for 35% of the province's total installed coal capacity. The next two largest owners, China Energy Investment and Huaneng Power International, two of the central government-owned companies, hold 10% and 8% of Guangdong's total installed coal capacity.

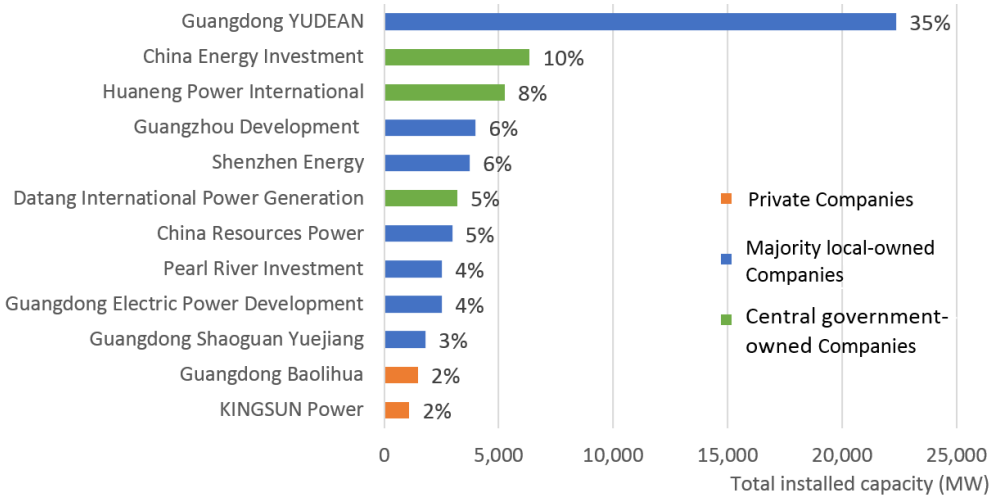

Figure 2. Top Companies that Representing 90% of Total Installed Capacity and Their Capacity Shares

Guangdong's coal units have a significant amount of outstanding debt. We estimate that these units owe nearly 94 billion yuan (~US$14 billion, nominal yuan) in total debt principal and interest, based on 15-year average loan repayment periods. Annual debt service payments for existing coal units peaked in 2015 and will be fully repaid in 2032, assuming no changes to repayment schedules (Figure 3). (Figure 3 includes both historical and future debt payments for existing units; thus, for instance, an existing unit built in the year 2000 will begin making debt payments in 2000.)

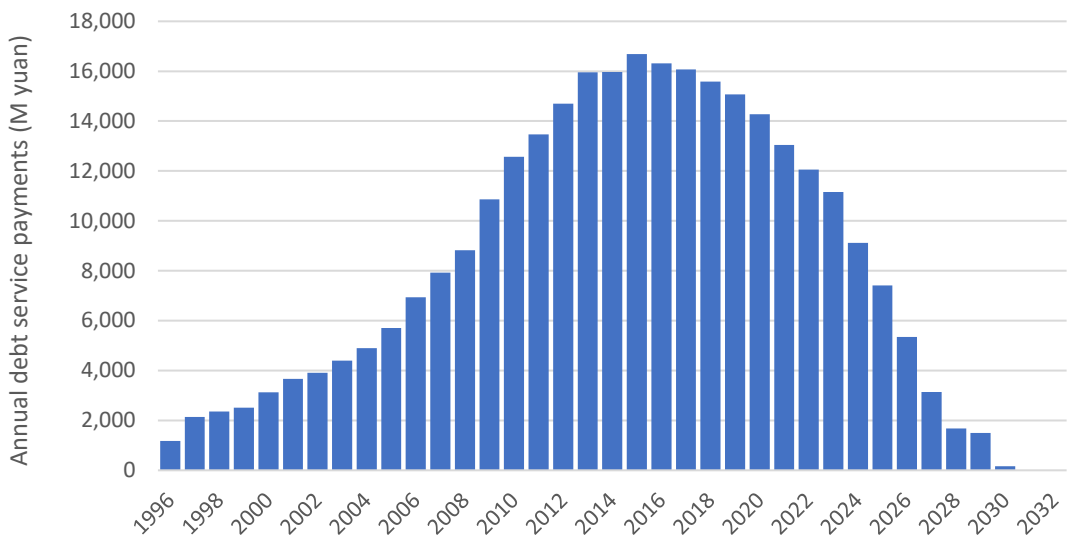

Figure 3. Estimated Historical and Future Annual Debt Service Payments for Existing Coal Generators in Guangdong

Significant levels of outstanding debt are tied to the industry preference for debt financing for power projects in Guangdong, and in China more broadly. Our estimates in this analysis are based on a capital structure with 80% debt.

Scenario Results

Because most of Guangdong's coal capacity consists of large and new units, the going forward fixed cost curve (see *Methods* section for definitions) for the province's coal units is relatively flat. For most of the curve, going forward fixed costs are less than 200 yuan/kW-yr. The curve kinks when cumulative capacity reaches small on-site CHP plants and rises to a high of around 550 yuan/kW-yr (Figure 4). Differences in going forward fixed costs among units are driven by economies of scale.

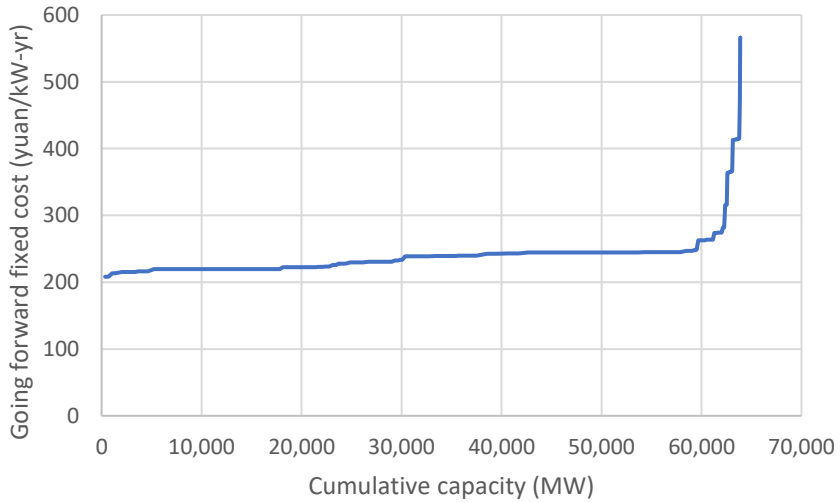

Figure 4. Generator Going Forward Fixed Costs by Cumulative Capacity under the Low Market Price Scenario

In the Benchmark scenario, all but two small on-site CHP plants have positive operating profits (Figure 5a and Figure 5b)—net revenues minus going forward fixed costs. Newer and larger plants have higher operating profits Figure 5c and Figure 5d).

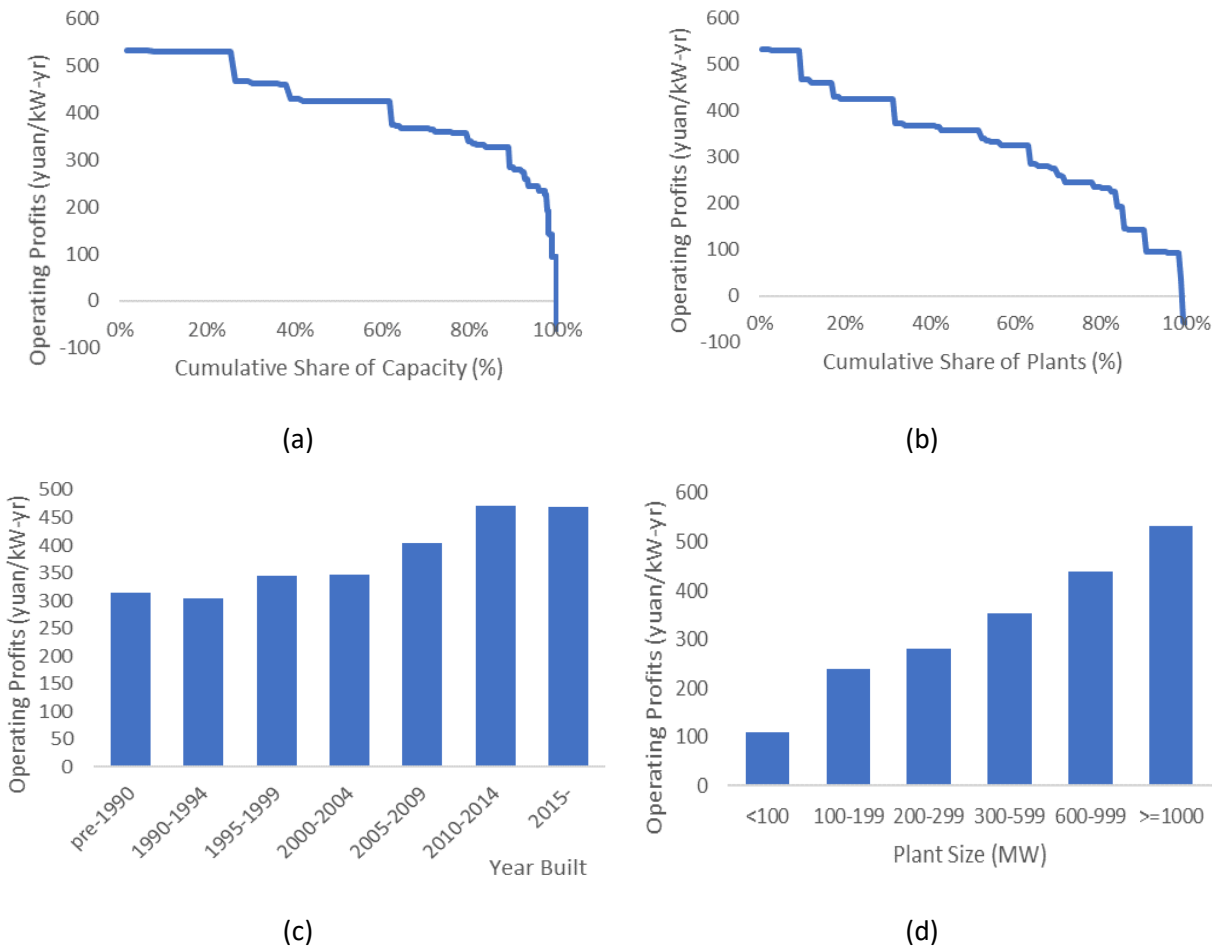

Figure 5. Operating Profits in the Benchmark Scenario

In the Low Market Price scenario, only about 20% of plants, representing around 40% of total installed capacity, have positive operating profits (Figure 6a and Figure 6b). These percentages are improved to 30% (of all plants) and 60% (of installed capacity) in the High Market Price scenario. In the Low Market Price scenario, only units larger than 1,000 MW and built after 2010 have positive operating profits (Figure 6c and Figure 6d).

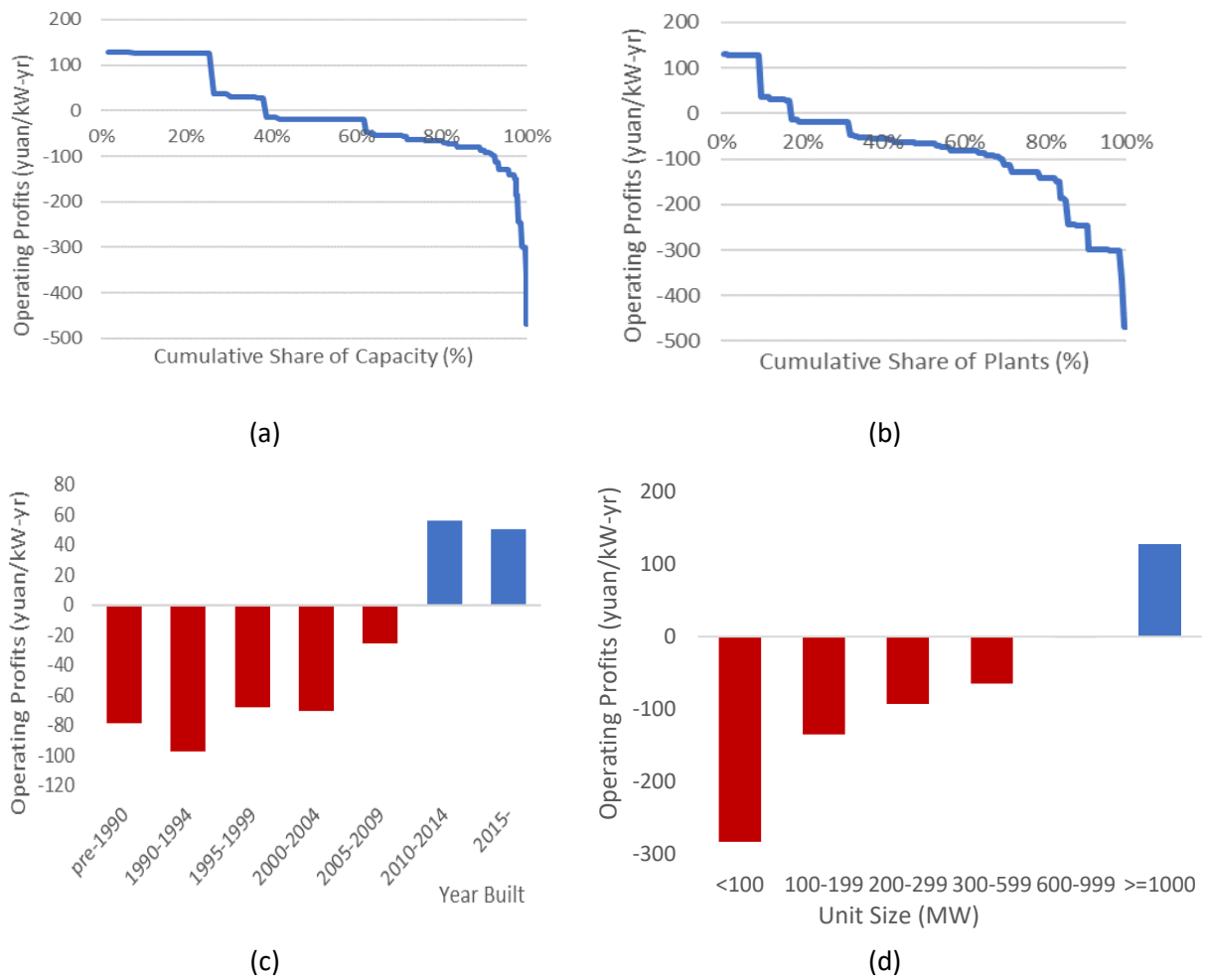

Figure 6. Operating Profits in the Low Market Price Scenario

Operating profits are used to pay annual debt principal and interest, with the remainder used to pay income taxes and to provide return of and on equity capital. Figure 7 shows total operating profit and annual debt interest and principal payments for each plant in the Benchmark and Low Market Price scenarios. Unit IDs are assigned to each unit in the order of their size (largest to smallest) and then year built (newest to oldest), with 1 representing the largest and newest unit. Units with zero debt principal and interest payments have already paid off their debt.

As shown in Figure 7, in the Benchmark scenario all but 10 units have high enough operating profit to pay annual debt interest and two-thirds of units can pay their full annual debt principal.[8] However, in the Low Market Price scenario, no units can pay their full annual debt interest. In the High Market Price scenario, 13% of units can pay their full annual debt interest and 4% of units can pay full annual debt principal.

[8] The fact that all units do not have positive net income in the Benchmark scenario should not be surprising. Some of these units are CHP and thus have an additional source of value or revenue in heat supply. Additionally, the benchmark tariff was never intended to ensure that all units fully recover their costs, but rather to provide a fair opportunity for doing so over time.

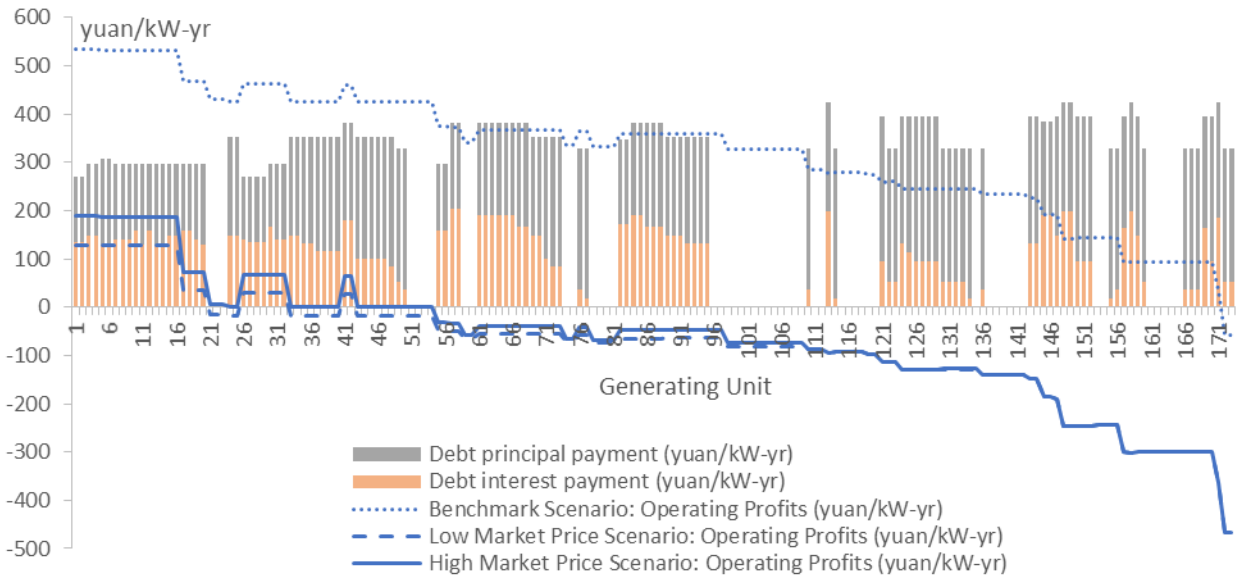

Figure 7. Operating Profit, Debt Interest Payment, and Principal Payment by Unit, Benchmark, Low and High Market Price Scenarios

At a corporate level, 7 out of the 30 companies have positive operating profit and no companies can pay their full annual debt interest in the Low Market Price scenario. In the High Market Price scenario, 8 out of the 30 companies have positive operating profit and 2 (Huaneng and Datang) can pay their full annual debt interest. As shown in Figure 8, in the Benchmark scenario the top 10 companies by installed capacity have relatively high operating profits. However, their operating profits drop significantly under the Low Market Price and High Market Price scenarios, with one-third of these companies having negative operating profits. This means that their net market revenues are less than their going forward fixed costs.

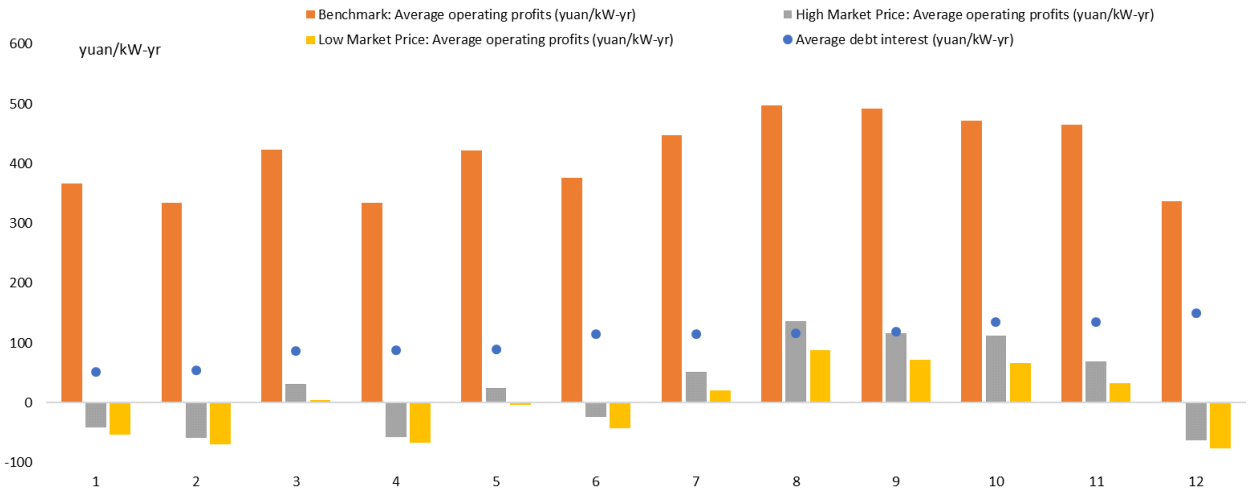

Figure 8. Average Debt Interest and Average Operating Profit by Scenarios of the Top 12 Companies

To what extent would capacity payments ease the financial impact of wholesale market pricing on coal generators? Figure 9 shows operating profit by coal generating unit, ranked from highest to lowest, for the three price scenarios (Benchmark, Low Market Price, High Market Price). In addition, Figure 9 shows the effect on operating profits of paying generators an additional 100 yuan/kW-yr and 400 yuan/kW-yr in capacity payments in the Low Market Price scenario, with 100 yuan/kW-yr representing a potential competitive price for capacity in an oversupplied market and 400 yuan/kW-yr representing a competitive price is a market in need of new investment [7].

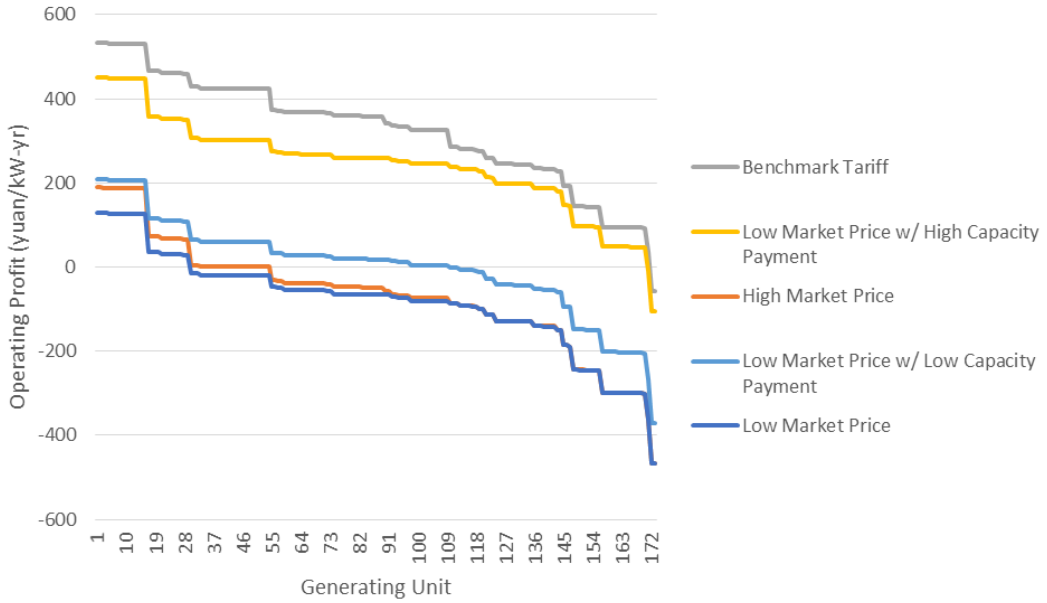

Figure 9. Coal Generator Operating Profit by Unit and Scenario

As Figure 9 shows, capacity payments—or equivalently some form of scarcity payments—could mitigate some, but not all, of the financial impact of market pricing on coal generators. With a 400 yuan/kW-yr capacity payment, generator operating profits are, on average, 25% less than they would be under the benchmark tariff. Thus, even when new investment is needed competitive prices are likely to be lower than the benchmark tariff, raising the possibility of stranded investments.

Conclusions and Discussion

Electricity markets are premised on the notion that generating companies take on more risk for investment cost recovery than utilities and independent generators did under a planned or regulated investment paradigm. This paper examined the implications of market reform for generation investment cost recovery in China, focusing on coal generation in Guangdong Province. Guangdong has announced plans to establish a spot market for electricity by 2019.

The analysis was based on Low Market Price (medium-level coal price, high hydro year) and High Market Price (high coal price, low hydro year) scenarios where average market prices are set by a mid-merit (330-340 kgce/MWh) coal unit. These prices are based on modeling of economic dispatch in Guangdong.

They are consistent with the province's generation mix, in which coal accounts for more than 80% of thermal generation.

In both the Low and High Market Price scenarios, coal generators are not able to repay their full annual debt interest and principal. In the Low Market Price scenario, only 20% of coal units (40% of capacity) are able pay their going forward fixed costs. In the High Market Price scenario, only two generating companies are able to pay their full annual debt interest.

Nearly 20% of Guangdong's coal capacity is CHP. These units tend to be smaller and more expensive. However, the impact of electricity market pricing on CHP units is uncertain because a large fraction of their value may come from providing heat rather than electricity. The integration of CHP units into electricity markets in Guangdong, and in China more broadly, will have a significant impact on market outcomes because these units may be less sensitive to the operational and reliability needs of the electricity system. In U.S. independent system operator (ISO) operated markets, ISOs encourage greater flexibility from CHP units by requiring all generation, including CHP units, to be settled at spot market prices.

Coal generators in Guangdong have an estimated 94 billion yuan in total outstanding debt, with total estimated debt service payments of around 16 billion per year in 2016. The inability to service this debt would have significant implications for China's electricity sector, given both its size and the sector's heavy reliance on debt financing. It raises questions about the compatibility of competitive electricity markets, on the one hand, and state-owned generation companies that rely on state-owned banks for as much as 80% of their capital, on the other.

The results raise a natural question: Why would coal generators perform so poorly in Guangdong's electricity market? The main reason is that Guangdong has an excess of large baseload generation relative to what would be expected in a competitive market. Our market price scenarios (load-weighted average 302 yuan/MWh [US$44/MWh] and 371 yuan/MWh [$55/MWh]) are not abnormally low, relative to competitive electricity markets in other countries. For instance, these prices are on par with or higher than recent day-ahead market costs in California (US$35/MWh to US$49/MWh from 2013-2017) [8].

However, large coal units have relatively high fixed O&M and investment costs, requiring high capacity factors (operating hours) and sustained high prices to generate the high net revenues that will allow for recovery of these costs. In Guangdong, LSEs would be unlikely to sign contracts with or build new coal units based on expected short-run energy market prices. The large number of existing coal units in Guangdong that would potentially be unable to recover their going forward fixed costs under market pricing raises questions about the short-term political viability and reliability impacts of electricity markets in the province, and in China more broadly.

The challenge of how to deal with market impacts on coal generators in Guangdong and China involves two separate issues that may have a common solution. The first of these issues is transition: Guangdong has an excess of baseload coal generation capacity relative to what expected near-term market prices would be able to support. The second of these issues is long-term resource adequacy: existing coal generators that cannot pay their going forward fixed costs would be forced to mothball or retire.

Transition involves broader questions about the "regulatory compact" between the government and state-owned generation companies and banks: should the government allow companies and banks to recover investment costs for coal units that were constructed under a different regulatory paradigm? Government agencies may decide to make transition payments to existing coal generators, in the interest of fairness, but delay dealing with mechanisms for long-term resource adequacy. The challenge with this approach will be in setting reasonable levels and duration for payments, ensuring that new generators are not eligible to receive transition payments, and avoiding creating new operational efficiencies.

Developing mechanisms for long-term resource adequacy would allow coal generators to recover at least some of their transition costs. If capacity or scarcity prices are high—signaling the need for new investment—coal generator operating profits would be closer to, though still significantly lower than, existing tariffs. We argue that this approach may present a better balance between consumer savings and easing the financial impact of reforms on generators than making transition payments.

Regardless of approach, it is important that China's policymakers anticipate and address the impacts of electricity market reforms on existing coal generators, developing politically viable solutions. Electricity markets could play an important role in China's transition to a low-carbon energy system. However, if markets stumble on transition issues their potential may not be realized.

References

[1] S. Stoft, Power System Economics: Designing Markets for Electricity, Piscataway, NJ: IEEE Press & Wiley-Interscience, 2002.

[2] G. Rothwell and T. Gomez, Electricity Economics: Regulation and Deregulation, Piscataway, NJ: IEEE Press & Wiley-Interscience, 2003.

[3] J. Pfeifenberger and S. Newell, "Trusting Capacity Markets: Does the lack of long-term pricing undermine the financing of new power plants?,"*Public Utilities Fortnightly,* 2011.

[4] P. Cramton and S. Stoft, "The Convergence of Market Designs for Adequate Generating Capacity," A White Paper for the Electricity Oversight Board, 2006.

[5] P. Cramton, A. Ockenfels and S. Stoft, "Capacity Market Fundamentals," *Economics of Energy & Environmental Policy,* vol. 2, no. 2, pp. 27-45, 2013.

[6] P. L. Joskow, "Competitive Electricity Markets and Investment in New Generating Capacity," in *The New Energy Paradigm*, Oxford University Press, 2007.

[7] M. T. Maloney, R. E. McCormick and R. D. Sauer, "On Stranded Cost Recovery in the Deregulation of the U.S. Electric Power Industry," *Natural Resources Journal,* vol. 37, pp. 59-123, 1997.

[8] C. Woo, D. Lloyd, R. Karimov and A. Tishler, "Stranded cost recovery in electricity market reforms in the US," *Energy,* vol. 28, pp. 1-14, 2003.

[9] U. C. B. Office, "Electric Utilites: Deregulation and Stranded Costs," CBO, Washington, D.C., 1998.

[10] A. Kahn, "Introducing Competitoin to the Electricity Industry in Spain: the Role of Initial Conditions," *Utilities Policy,* vol. 7, pp. 15-22, 1998.

[11] P. L. Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector," Center for Energy and Environmental Policy Research Discussion Draft, Cambridge, MA, 2000.

[12] S. Hempling, K. Rose and R. E. Burns, "The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market," A Briefing Document for State Commissions, 1994.

[13] W. J. Baumol and G. Sidak, "Stranded Cost Recovery: Fair and Reasonable," *Public Utilities Fortnightly,* pp. 22-23, 1995.

[14] R. J. Michaels, "Stranded Investment Charges: Inequitable and Inefficient," *Public Utilities Fortnightly,* pp. 24-25, 1995.

[15] B. Black, "A Proposal for Implementing Retail Competition in the Electricity Industry," *The Electricity Journal,* vol. 7, no. 8, pp. 58-72, 1994.

[16] T. J. Brennan and J. Boyd, "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts," *Journal of Regulatory Economics,* vol. 77, pp. 71-92, 1997.

[17] G. J. Sidak and D. F. Spulber, Deregulatory Takings and the Regulatory Contract, Cambridge, UK: Cambridge University Press, 1997.

[18] G. J. Sidak and W. J. Baumol, "Stranded Costs," *Harvard Journal of Law & Public Policy,* vol. 18, pp. 835-849, 2001.

[19] S. Rose-Ackerman and J. Rossi, "Disentangling Deregulatory Takings," *Virginia Law Review,* vol. 86, pp. 1435-1496, 2000.

[20] R. J. Michaels, "Unused and Useless: The Strange Economics of Stranded Investment," *The Electricity Journal,* vol. 7, no. 8, pp. 12-22, 1994.

[21] P. M. VanDoren, "The Deregulation of the Electricity Industry: A Primer," Cato Institute, Washington, D.C., 1998.

[22] L. Baxter and E. Hirst, "Estimating Potential Stranded Commitments for U.S. Investor-Owned Utilities," Oak Ridge National Laboratory, Oak Ridge, TN, 1995.

[23] W. B. Tye and F. C. Graves, "The Economics of Negative Barriers to Entry: How to Recover Stranded Costs and Achieve Competition on Equal Terms in the Electric Utility Industry," *Natural Resources Journal,* vol. 37, pp. 175-250, 1997.

[24] P. Fox-Penner, Electric Utility Restructuring: A Guide to the Competitive Era, Vienna, VA: Public Utilities Reports, Inc., 1997.

[25] E. Hammond and J. Rossi, "Stranded Costs and Grid Decarbonization," George Washington University, Washington, D.C., 2016.

[26] B. Caldecott and J. McDaniels, "Stranded generation assets: Implications for European capacity mechanisms, energy markets and climate policy," University of Oxford, Oxford, 2014.

[27] J. Lin, F. Kahrl, J. Yuan, Q. Chen and X. Liu, "Electricity Market Transition in China: A Case Study of Guangdong Province," Berkeley-Tsinghua Joint Research Center, Berkeley, CA, 2018.

[28] California Independent System Operator (CAISO), "2017 Annual Report on Market Issues & Performance," CAISO, Folsom, 2018.

[29] F. Kahrl, J. Williams, J. Ding and J. Hu, "Challenges to China's transition to a low carbon electricity system," *Energy Policy,* vol. 39, no. 7, pp. 4032-4041, 2011.

[30] J. Ma, "On-grid electricity tariffs in China: Development, reform and prospects," *Energy Policy,* vol. 39, no. 5, pp. 2633-2645, 2011.

[31] C. Ma and L. He, "From state monopoly to renewable portfolio: restructuring China's electric utility," *Energy Policy,* vol. 36, no. 5, pp. 1697-1711, 2008.

[32] T. M. Johnson, "China's power industry, 1980–1990: Price reform and its effect on energy efficiency," *Energy,* vol. 17, no. 11, pp. 1085-1092, 1992.

[33] A. DeBenedictis, D. Miller, J. Moore, A. Olson and C. Woo, "How big is the risk premium in an electricity forward price? Evidence from the Pacific Northwest," *The Electricity Journal,* vol. 24, no. 3, pp. 72-76, 2011.

[34] S. Bornstein, J. Bushnell, C. Knittel and C. Wolfram, "Inefficiencies and Market Power in Financial Arbitrage: A Case Study of California's Electricity Markets," *The Journal of Industrial Economics,* vol. 56, no. 2, pp. 347-378, 2008.

[35] P. Andrews-Speed, S. Dow, A. Wang, J. Mao and B. Wei, "Do the Power Sector Reforms in China reflect the interest of consumers?," *China Quarterly,* vol. 15, pp. 430-446, 1999.

[36] S. Xu and W. Chen, "The Reform of the Electricity Power Sector in the PR of China," *Energy Policy,* vol. 34, no. 16, pp. 2455-2465, 2006.