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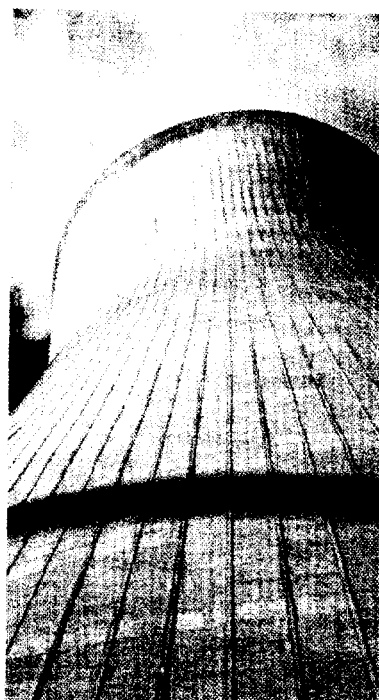
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Fostering Competition in China's Power Markets



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Fostering Competition in China's Power Markets

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Foreword

Over the past several years China has implemented many far-reaching reforms in the power sector, transforming it from a government agency to a modern, commercial industry with increasing private participation. Competition in the power sector has now become a key driver for future reforms to achieve financial and economic efficiencies that are not possible under current structural and institutional arrangements. The Chinese power sector is, in essence, entering the final stage of its shift to market principles.

In fostering competition in China's power markets, there is vast international experience from which to draw lessons, as well as numerous market designs and implementation strategies. These lessons, designs, and strategies need to be distilled into a comprehensive and consistent approach that is sensitive to the circumstances and reform objectives in China's power sector. This report attempts to provide the foundation for such an approach.

This report is not intended to provide a detailed blueprint for implementing competitive power markets in China. But it does provide recommendations, rationales, and options for certain market design choices that will have to be made, as well as suggestions for detailed studies to implement them.

This report has emerged from almost three years of policy discussions, technical studies, and market implementation trials. It builds on the individual contributions of a large number of international specialists and Chinese power industry experts and policymakers. This work would not have been possible without the support and cooperation of the State Power Corporation of China and its continued patience from inception to completion. I believe that the same elements of international cooperation, detailed analysis, and patience will lead to success in implementing competition in China's power markets.

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Abstract

This report proposes a strategy for developing competitive pool markets in China's power sector and for increasing energy trade between competitive pool market areas. A three-stage approach is offered for developing the competitive pool markets. During stage 1 a mandatory competitive pool will be created with a single buyer. During stage 2 wholesale competition will be permitted. During stage 3 retail competition will be allowed, making the market fully competitive.

The staged approach allows competitive market principles to be introduced immediately within existing institutions. This will allow needed skills and parallel economic reforms to be developed gradually and so facilitate increased competition in later stages. The report also discusses key elements of competitive market development, including the organization of transmission services and transition issues such as dealing with stranded costs and mitigating market power among generators.

Acknowledgments

This report was derived from the ideas, experience, and knowledge of a diverse group of Chinese and international experts. The three main authors are Noureddine Berrah, Ranjit Lamech, and Jianping Zhao, all with the World Bank. But many other people contributed to the report, addressing closely related topics and so making the exact boundaries of individual contributions impossible to demarcate. Three contributions in particular formed the building blocks of the strategy outlined in the report. First, the proposed competitive power pool design and staged implementation (chapter 2) came from work by Pacific Power International (Australia) for the pilot power market in Zhejiang province. This work was undertaken during the preparation of the World Bank's Tongbai Pumped Storage project. Peter Egger (Phacelift, Australia) played a key role in developing the three-phase strategy for the competitive pool market.

Second, the proposed scheme for bilateral power trading between competitive pool markets (chapter 3) was derived from the work of Barker, Dunn & Rossi, Inc. in designing a regional trading scheme between the provincial and municipal systems in the East China region. This work was undertaken during the implementation of the World Bank's East China (Jiangsu) Transmission project. The contributions of Jim Barker and Jack Zuckernick, both of Barker, Dunn & Rossi, Inc., deserve special mention.

Third, the discussion of transmission issues emerged from the inputs of Luis Caruso (Mercados Energéticos, Argentina), Peter Egger

(Phacelift, Australia), Sally Hunt (National Economic Research Association, United States), Mario Pereira (PSR, Inc., Brazil), Bernard Tenenbaum (World Bank), and Frederic Albouy, Frederic Jouve, and Patrick Pruvot (Électricité de France International, France). Other contributors to the report included Harvey Salgo (LaCapra Associates, United States), Jon Stern (National Economic Research Association, United States), and Ray Tomkins (Economic Consulting Associates, United Kingdom).

The team from the State Power Corporation of China participated in all phases of the work, providing inputs on the government's reform objectives and discussing and commenting on the report during various stages. Special thanks are expressed for the team's dedication and hard work. The team was led by Zou Chijia and consisted of Cou Ming, Zhao Shehong, Liu Shu, Tang Zhongnan, Yi Maosong, Bai Xiaoming, Ge Guochuan, Han Fang, Bai Jianhua, and Cai Gaofeng.

Laszlo Lovei, Jean-Francois Bauer and Kari Nyman served as peer reviewers, and the authors are grateful for their insightful comments and suggestions. Gautam Ivatury provided important research assistance. Elaine Sun and Ma Rui provided valuable assistance in organizing workshops and missions. The report was edited by Paul Holtz and laid out by Megan Klose, both with Communications Development Incorporated, Washington, D.C.

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Institutional Development Fund, China country unit and the Energy Sector Management Assistance Programme (ESMAP).

Although there was wide consensus on objectives and motives for introducing competition in China's power sector, the market design choices, tradeoffs, and recommendations were

not as easy to agree on. The authors would like to believe that the opinions and recommendations are shared by all who contributed to this report. But the authors are solely responsible for all the views expressed, all the conclusions reached, and any errors of fact and interpretation that remain.

Executive Summary

China has made impressive progress in reforming and commercializing its power sector. Today it has the world's second largest power system, with more than 300 gigawatts of installed capacity. Moreover, it produces about 1,250 terawatt-hours of electricity. But the single buyer model has reached its limits, and a new approach is needed.

Great Strides Have Been Made...

In the early 1980s electricity was considered a social service, and power was provided through a centralized government department with units at the province, prefecture, municipality, and county levels. Investments were centrally decided and financed through budget allocations. Prices were totally controlled and covered only a small portion of supply costs. Private ownership of power assets was illegal.

Today all provincial power enterprises have been fully corporatized and operate as commercial businesses. The State Power Corporation of China, established in 1997, holds the state's ownership rights in these companies on a commercial equity-holding basis. Although most investments still require central approval, budget allocations have been phased out and subsidies eliminated. Investments are financed through equity and debt from a variety of public and private sources.

Electricity prices are generally in line with or higher than long-run marginal supply costs in most—notably the largest—grids. Private ownership of power assets, piloted since the mid-

1980s, was formalized by the 1995 Electricity Law. By late 1999 some 40 projects involving private developers were operating or under construction, with installed capacity totaling 28 gigawatts. And 37 power companies, with installed capacity of 25 gigawatts, were listed on international and domestic stock markets.

...But New Steps Are Needed

Still, China's power sector faces problems that, if not addressed, could jeopardize these achievements. The main problems are structural, and arise from a piecemeal approach to restructuring the sector and weak incentives for efficient investment and resource use. The single buyer structure at the provincial level, which fostered new investments and allowed gradual price increases, has reached the limits of its usefulness, particularly in advanced provinces.

Among the signs of these problems:

- Provincial power companies have breached contracts to purchase power—particularly in 1998–99, when growth in the demand for electricity slowed temporarily—indicating an abuse of the single buyer's dual monopsony and monopoly power.
- Single buyers have engaged in discriminatory dispatch, favoring plants owned by provincial power companies over more efficient plants owned by independent producers—implying an abuse of monopsony power and sub-optimal use of available capacity.

- Little effort has been made to cut investment and operating costs and to achieve economies of scale through interprovincial trade and cooperation.
- Highly polluting small coal plants have proliferated, with little consideration of their environmental impacts or of the optimal use of natural resources—stemming from the preferences for local generation held by provincial single buyers (because it means more profits) and local governments (because it means more revenue).
- Cost-plus pricing policies have allowed rapid debt paybacks, with loan maturities much shorter than the economic lives of generation units—leading to high front-loaded generation prices and discrimination against capital-intensive and environmentally friendly technologies.
- Flawed prices have led to inefficient dispatch, underinvestment in transmission, misused resources, and avoidable environmental impacts—because prices do not reflect actual supply costs along the generation, transmission, and distribution chain.
- Accommodate the wide diversity in regional and provincial power systems (which range from 300–30,000 megawatts), generation mix (with coal-fired capacity accounting for 50–98 percent of the total), development of transmission networks, and so on.
- Allow adequate time for power entities to acquire the management capacity and skills to adapt to competition, and for the government to establish a modern regulatory framework.

Given the diversity in power systems and institutional capacity, competitive power pools should be implemented at the provincial or regional level, in parallel with price-based bilateral trading arrangements for power exchanges between competitive pools. Market rules and market development should be coordinated to ensure that future integration is not compromised.

This report is not a blueprint for power sector reform in China. Rather, it offers market design principles and priorities to guide the government and companies in defining and implementing competitive power markets. A building-block approach is stressed that progressively expands competition within competitive market areas and facilitates gradual integration. Specific studies and consultation of all stakeholders will be required to translate these market design principles into detailed market designs with suitable rules and operating procedures.

Recognizing these problems, the government has initiated comprehensive reform to introduce and expand competition—starting with generation in the short term (next 2 years) and extending it to the wholesale level in the medium term (2–5 years) and to the retail level over the long term (5–10 years). This gradual transition to competitive markets will increase investment and efficiency and empower consumers. The government has mandated the separation of generation from transmission and distribution, selected six provinces to test competitive generation markets, and started revising the Electricity Law to provide a stronger legal basis for reform.

Experience in many other countries and in other sectors in China indicates that competition will provide strong incentives for increasing operating efficiency and optimizing resource use—leading to lower prices for consumers. The efficiency benefits of competitive generation markets are beginning to materialize in Zhejiang province, which is leading the pilot market implementation effort.

A flexible approach is needed to develop competitive power markets in China to:

The Transition to Competitive Power Markets

Competitive power markets in China will initially be established in areas or regions made up of several provinces. Technical and organizational factors will limit the creation of larger market areas at the outset. At the minimum, the competitive market area will contain a single province. A three-stage process can be used to introduce and expand competition within these defined market areas.

Stage 1: the mandatory pool with a single buyer

Stage 1 will introduce competition in generation by mandating that all generators submit price bids into a pool in order to be dispatched. A common market-clearing pool price will be

determined by the price of the last generator dispatched to meet total system demand. At this stage the regional (or provincial) power company will remain the single buyer of all the electricity produced by generators connected to the main transmission grid, as well as the sole wholesale electricity supplier.

Revenues for generators will depend on their electricity production, which will be valued at the pool-clearing price adjusted (positive or negative) in accordance with the contract for differences agreed to beforehand with the single buyer. The contract for differences guarantees generators minimum revenue if unit availability meets contract requirements. It also minimizes price volatility for the single buyer. At this stage the contract for differences is the only risk-hedging instrument available to generators and the (single buyer) purchaser.

This stage is required in China—as it might be in other developing countries—for several reasons. Consumers and wholesalers (distributors) may have limited access to electricity suppliers (generators, traders) because of existing laws and regulations. Distributors and large consumers—mostly state-owned companies—are being restructured and do not yet have the management and negotiation skills required to secure electricity supplies in competitive markets at least cost. Metering and computerized billing and settlement systems are inadequate. And there is little or no experience with commodity trading and risk-hedging instruments.

Four key operational benefits are expected at this stage. First, productive and allocative efficiency will improve because generating plants, subjected to competition and economically dispatched based on price bids, will have incentives to maximize availability and cut operating costs. Second, government agencies and market players will have time to carry out the required restructuring of the sector and develop functions (such as risk management skills) essential for the stable operation of a competitive market. Third, experience will be gained with developing and regulating competitive market rules. Fourth, a transparent spot market price will emerge, providing market participants with information on price volatility and risk. This would provide essential information to guide contracting

between generators and the single buyer (and later wholesalers). In addition, generators' access to consumers could be tested, on a limited scale, by allowing sophisticated large consumers and wholesalers to negotiate and contract directly with generators.

Stage 1 must be considered transitional, lasting only as long as is needed to achieve the smooth functioning of a mandatory pool for generators and complete essential restructuring. Delays in moving to stage 2 could lead to the abuse of dual wholesale monopsony and monopoly power by single buyers, enabling them to capture all the benefits of competition at the generation level and reducing incentives for efficient wholesale contracting. This would undermine the confidence of generators and consumers in competitive markets and ultimately stall reform.

Stage 2: wholesale competition

Stage 2 will expand competition to the wholesale level by allowing distributors, traders, and large consumers to contract directly with generators and purchase power from the mandatory pool. The operations and functions of the pool will not change. The obligations of single buyers under the original contracts for differences will be transferred to distributors, traders, and eligible consumers according to agreed procedures. Contracts for differences will continue to be the main instruments for managing risk and can at this stage be freely negotiated between generators and purchasers.

Generators will continue to receive revenues based on electricity sales to the pool at the market-clearing price, adjusted in accordance with contracts for differences with eligible consumers and wholesalers. Consumers who are not eligible to access the market will continue to be served by distributors in their franchised areas. Secondary trading of financial obligations under contracts for differences should be allowed between market participants to expand risk management possibilities and increase market efficiency.

Abolishing the single buyer and increasing the number of purchasers will increase the competitive pressures on generators, leading to bigger reductions in supply costs and prices—assuming, of course, that generation activities are restructured to

mitigate the possibility of generators having market power. Transmission will become a completely independent service during this stage, requiring an effective pricing scheme to compensate for the service and provide incentives for expansion.

Stage3: retail competition

Stage 3 will extend the benefits of competition and choice to all segments of the market by enabling all consumers to choose their electricity retailer. Developing retail markets requires separating the operation and management of the distribution network from commodity trading. The distribution network will remain a monopoly and will have to be regulated. But commodity trading will be increasingly opened to new entrants, increasing competitive pressures to cut both retail margins and wholesale prices. Small residential and commercial consumers who do not wish to choose between retailers will be assured supply at regulated prices from the retailers serving their franchised area.

Allowing consumers to choose their retailer will create a competitive commodity market in which prices are determined by supply and demand and adjusted automatically without administrative interference. (Though it is assumed that power market issues will be properly addressed and that monopoly segments of the industry—transmission, distribution—will be adequately regulated.) Only a few countries have reached this level of competition in the electricity sector. But they have achieved, after an adjustment period, significant efficiency gains and lower consumer prices.

Bilateral Trade between Competitive Power Markets

Although competitive power markets will greatly improve operating efficiency and resource use, trading between these markets will allow even more benefits. Such trade will enable the optimal development of national resources, reduce the operating reserves required for adequate supply, and encourage more efficient use of installed capacity. Bilateral power trading between markets will also provide more choices for generators and wholesalers, increasing pressures to cut supply costs and improve efficiency.

Trading between markets should be voluntary. As market participants become more comfortable with trading arrangements and the mutual benefits become evident, trade will expand. There are three broad categories of transactions: long-term capacity or energy (one to several years), short-term capacity or energy (one day to several months), and hourly (or shorter) spot energy.

An institution will be required to develop and facilitate trade between separate competitive markets. An existing institution could be designated to perform the required functions, or a new institution will have to be created. It will also be useful, as a first step, to abolish administrative quotas and so allow power exchanges to be based entirely on commercial considerations—specifically, cost and profit margins for sellers and value to buyers. Fiscal distortions and other institutional barriers to power trade should also be eliminated to encourage interprovincial exchanges.

To provide the flexibility needed to accommodate trading between competitive markets at different stages of development, it is recommended that trading be based on prices rather than costs. This report recommends that long-term and short-term transactions be negotiated directly between participants and that spot energy transactions be intermediated by an energy broker. The trading scheme can be structured with incentives for expanding the transmission network between competitive market areas—crucial for increasing the possibilities for and volume of power trade—and eventually to integrate competitive market areas.

At some point in the future, bilateral trading across competitive markets can be replaced by a fully integrated competitive power market. This would be possible if common competitive market principles are established in the smaller competitive areas.

Structural and Regulatory Reforms to Reap the Benefits of Competition

The report identifies the structural and regulatory changes required to move from one stage of reform to the next. Reforms in industry structure and the development of regulations must be carefully synchronized with market implementa-

tion to achieve the benefits of competition. Three issues require special attention.

Separating ownership of generation from ownership of transmission and distribution

Fully separating generation from transmission and distribution is key for creating true competition at the generation level. China began diversifying ownership at the generation level in 1986, and several generation companies operate in all provinces. But partial or full ownership of generation assets by regional and provincial single buyers remains a serious potential (and in some cases actual) hindrance to competition. To achieve the conditions for competition, there should be no ownership linkages between single buyers and generators.

Competition between generators requires that there be enough separately owned generation companies. Moreover, government ownership of generation should be assigned to separate corporate entities, with a view to full divestiture. The managers and boards of directors of these separately incorporated generation companies should be given full decisionmaking autonomy and incentives for maximizing profits.

International experience has shown that horizontal market power can arise when there are *dominant generation firms or collusion between related firms*—severely distorting dispatch (through discrimination or bidding strategies), weakening competition, and leading to high prices. Methods of recognizing the potential for market power and strategies to mitigate it are reviewed in the report.

Separating transmission and distribution

Wholesale markets will be established to allow multiple sellers and buyers to freely trade electricity. These markets will require separating transmission and distribution and giving generators open access to the transmission network. This complex structural change will require careful planning and implementation—and is one of the top priorities during the transition.

During stage 1, efforts should focus on recognizing transmission as a distinct service in the power supply chain and establishing it as a profit

center, on separating transmission and distribution accounts and applying full-cost-based transfer prices to all power transactions to avoid distortions and hidden cross-subsidies, and on organizing distributors owned by the single buyer as profit centers—with a view to creating them as separate autonomous companies before the transition to wholesale competition in stage 2.

Before wholesale competition is implemented, the transmission profit center and distribution profit centers must be incorporated as separate companies. A separate transmission entity will give generators and eligible consumers open access to the transmission network, allowing direct contractual relationships. The transmission entity could retain responsibility for system operations and market operations. If the system and market operator remain integrated with the transmission entity, it will be absolutely crucial to ensure the system operator's independence by having no linkage to sellers (generators) or buyers (retailers).

Transparent transmission pricing should be developed to ensure adequate compensation for existing assets and incentives for network expansion, to promote the optimal use of existing generation assets, and to guide siting and investment in new generation assets. The report offers a *phased strategy for implementing transmission prices first at generation nodes and later at all wholesale nodes*. Given the monopolistic nature of transmission, technical and economic regulation will remain important.

During stage 2, distributors (operating with combined network and retailer responsibilities) will be allowed to participate in the market and increase the number of buyers. Distribution bureaus should be restructured as autonomous companies obliged to supply the captive consumers within their franchise areas at regulated prices. Restructuring of distribution will require careful analysis because there are hundreds of distribution entities at the provincial level—some of which are autonomous from provincial power utilities—as well as a tradition of highly decentralized electricity retailing at the township and village levels.

Changes to the existing system (which has both problems and virtues) should be avoided

before comprehensive institutional studies are completed. These studies need to determine the appropriate size and scope of distribution companies for economic and financial viability and distributional efficiency. There is no universal model for organizing distribution activities: in power systems comparable to those in Chinese provinces the number of distribution companies ranges from two to four at one extreme to hundreds at the other. Fewer distributors would enable economies of scale and lower distribution costs, while more distributors would foster competition—with the possibility of lower operating costs and consumer prices. Ownership options should also be evaluated, especially if one of the government's objectives is to raise funds for developing the sector by divesting distribution assets.

Laws and regulations to support competitive markets

The development and principal requirements of comprehensive laws and regulations for the

power sector were discussed in a 1997 paper sponsored by the World Bank and China's Ministry of Electric Power (see *China: Power Sector Regulation in a Socialist Market Economy*, World Bank Discussion Paper 361). This report reiterates some of the key requirements and extends the discussion in several areas, including:

- Areas that require specialized regulatory supervision within competitive pool markets.
- The separation of responsibilities between the market operator and system operator and the regulator in the context of the mandatory energy pool.
- The challenge of establishing adequately staffed regulatory institutions with the requisite skills to effectively supervise competition in the power sector.
- The extent of the competitive market: transition possible under the 1996 Electricity Law and revisions needed to adapt to independently regulated, competitive markets.

Chapter 1

Competition As a Driver of Reform

Gradualism has been the hallmark of economic reform in China, including power sector reform. This approach—known in China as “crossing the river by feeling the stones”—has served the country and the power sector well. Typically, each reform has built on earlier reforms by broadening and deepening the scope of change and the possibilities for future reforms. Although the gradual approach has sometimes been perceived as being too slow, it has brought about impressive change while preventing serious economic disruptions and social upheaval.

The building block approach has been successful in the power sector for four reasons. First, the government has been able to set and focus on priorities at each stage rather than diffuse limited institutional capacity implementing reforms on multiple fronts. Second, policymakers have been able to pilot different approaches in a few provinces, await preliminary results, determine a preferred strategy, and then pass the enabling legislation required to mainstream the selected strategy. Third, the approach has made it possible to build broad consensus by acknowledging regional diversity in the power sector and trying alternative approaches to achieve the same objective. Fourth, and perhaps most important, the government has been consistent and determined in moving the power sector toward a commercially stable future.

Waves of Reform

In the early 1980s China’s power industry was organized as one large government department,

with provincial bureaus operating as local representatives of central and regional administrations. Managers had to refer all decisions to the top. Prices were low and controlled. The industry was fully vertically integrated and run as an administrative entity rather than a commercial business. All capital investment was financed through budget allocations.

In less than 20 years a remarkable transformation has occurred, creating a very different sector (table 1.1). Reform has occurred in waves. The first wave focused on raising prices, transforming government departments into corporations, phasing out budget financing, and experimenting with private sector involvement. The second wave stressed legislative reform, reduced vertical integration, and streamlined the government institutions supervising the sector. The power sector has now entered a third wave of reform, in which the strategic priority is fostering competition to guide resource allocation and further reduce administrative controls.

The first wave of reform

The first steps toward reforming China’s power sector occurred in the mid-1980s, when the government began curtailing budget allocations for power investments, instead providing debt through policy and commercial banks and introducing the “new plant, new price” policy. The “new plant, new price” policy ensured generators a cost-based tariff that enabled rapid debt repayments. This approach was used in conjunction with a single-part energy tariff linked to a

Table 1.1

Changes in the power sector as a result of reforms

Feature	Early 1980s	2000
Management and funding	Power entities managed as administrative departments of the Ministry of Energy, fully controlled and funded by the government.	Most entities have been corporatized and are run as for-profit enterprises. Budget allocations have been phased out and subsidies eliminated.
Sector structure	Vertically integrated companies own and operate generation, transmission, and distribution.	Generation is being separated from transmission and distribution.
Prices and regulations	Tariffs barely cover operational costs. Prices set by the government, often arbitrarily.	Average prices exceed supply costs in almost all provinces. Prices still need to be approved by the government, but the Electricity Law requires prices to cover supply costs.
Supply reliability	Severe energy shortages persist until the mid-1990s.	Energy shortages have been eliminated in all provinces. "New plant, new price" policy, combined with easy approvals for small projects, increased annual capacity additions from 4–5 gigawatts to 15–17 gigawatts in the mid-1990s.
Private ownership	Private ownership banned in the power sector.	Private ownership permitted in generation. Private investment accounts for significant share of new capacity. Some 40 independent power producers generate 28 gigawatts of power; 37 companies listed on domestic and foreign stock exchanges represent an installed base of about 25 gigawatts.

nominal load factor (typically 5,000–5,500 hours of operation at full capacity). As a result investment in generation became very attractive, easing power shortages. To increase decentralization, in 1988 policymakers granted provincial power companies greater control over labor and wages. Power companies were also allowed to retain part of their operating surpluses under a system known as the responsibility contract system.

In the early 1990s the government took steps to increase the commercial orientation of state enterprises. In 1992 it increased the autonomy of state enterprise managers. In 1993 it passed the Company Law, which for the first time allowed state power companies to be corporatized. The government also created new public corporations to raise foreign capital and experiment with new financing models. These entities, such as the Huaneng Group, eventually raised equity on foreign stock exchanges. During this period the Hopewell Group of Hong Kong built one of the first build-operate-transfer facilities in a developing country, paving the way for private investors to participate in the sector. Joint ventures (public-private partnerships) and their many variants

increased substantially, accounting for about half the installed capacity in several provinces by 1993. In 1993 the government also issued guidelines for new accounting standards that reflect international practice.

The second wave of reform

Reforms since the mid-1990s have increased the market orientation of the power sector and initiated a restructuring process conducive to competition. Four events are worth noting:

- The Electricity Law, promulgated in 1996, legalized the status of power enterprises as commercial entities. The law also established the legal basis for private ownership.
- In 1997 the State Power Corporation was established to hold the state's ownership rights in the power sector and support a commercial asset-holding relationship.
- In 1998 the State Economic and Trade Commission and its provincial counterparts were assigned responsibilities for sector regulation, separate from other government functions.
- In 1999 the State Council issued a directive to separate generation from transmission and distribution.

The need for a third wave of reform

Impressive gains were made in the first two waves of power reform—notably the elimination of endemic power shortages and the adoption of an increasingly commercial operating framework. But the sector still faces problems. If these problems are not resolved quickly, they could jeopardize reforms and undermine many of the gains. The government is contemplating a third wave of reform to address these problems by introducing competition in the sector.

Growing inefficiencies in the single buyer structure

Expansion of the Chinese power system has relied on vertically integrated provincial power companies operating as the single buyers of all generated electricity—that is, as monopsonies. These buyers are obligated to meet all the demand within the system. To do so, they must contract for adequate supply and bear all market risk. Accordingly, provincial power companies have built up portfolios of their own power plants and contracts with independent power producers.

The single buyer model provided many benefits to China's rapidly growing power system. Lenders and investors had enough security to finance large capacity additions, mitigating the disruptive effects of power shortages. The single buyer's ability to average the lower prices of old generators (which had recovered their investment costs) and the much higher prices of new generators (which operated under the "new plant, new price" policy) allowed price increases to be phased in gradually—avoiding price spikes at times of capacity or energy shortages. The single buyer structure also gave power utilities time to build management capacity and adapt to a commercial environment.

But in many provinces the single buyer structure has reached its useful limits because there are weak incentives for investment and operating efficiency, and regulating the activities of a single buyer to enhance efficiency is difficult. Inefficiencies are evident in excessive generation capacity and in rigid pricing and contract structures. There has been little incentive to restrain excess capacity, and its costs have been passed on to consumers. The ability to

pass on such costs dilutes the strict commercial criteria that should be applied to investment decisions.

Problems are also emerging as a result of the single buyer's bargaining power over generators when signing contracts, and its ability to discriminate when dispatching installed capacity. In some provinces independent generators are not being dispatched at levels that cover their fixed costs or provide the revenues on which their investment decisions were based. Complaints about discriminatory dispatch have surfaced, with a growing perception that plants owned by provincial power companies are favored over independent producers.

Unexploited trade benefits and economies of scale

The chronic power shortages of the early 1980s led many local and provincial governments to adopt an inward-looking policy of self-reliance in generation capacity. With many provinces struggling to meet their own loads, the possibilities of trading power across provincial boundaries was not carefully considered. Thus the huge economic benefits from coordinating investments and operations over broad geographic areas have not been exploited, and investments in plants have not benefited from economies of scale. Instead there has been a proliferation of small coal-fired plants (50 megawatts and less), which are less efficient, more expensive, and more environmentally damaging than larger plants serving wider areas.

High bulk power and consumer prices

The "new plant, new price" policy attracted large investments in new generation. But these investments were highly leveraged—that is, they had a large share of debt relative to equity. Bulk electricity prices were set very high because investors, facing considerable institutional and regulatory risks, looked to rapid debt repayment to recover their investments. Today consumer prices are often higher than economic costs because of the mismatch between short-term debt maturities and the long economic life of assets. More important, with little or no competition in investment and project development, there are few incentives to cut capital costs.

Inefficient pricing

Although average prices cover supply costs, power pricing remains flawed. With few exceptions, generation tariffs are still based on a single-part structure linked to a nominal load factor—leading to uneconomic dispatch. Transmission is not recognized as a separate service, constraining power companies' ability to recover investment in transmission expansion. As a result new transmission capacity is insufficient, leading to suboptimal use of capacity at the provincial level and limited power trade between provinces.

Transmission and distribution bottlenecks

Bottlenecks are emerging in transmission and distribution networks, where inadequate funding and rapidly increasing demand have led to restrictions in the ability to serve load—although generation capacity has been available. The funding shortfalls have partly been a consequence of an excessive focus on generation, where the bulk of investment has gone at the expense of the transmission and distribution networks.

Benefits of Competitive Power Markets

In response to mounting operating and investment inefficiencies and deliberate barriers to interprovincial trade, the Chinese government plans to foster competition in the power sector and rely more on market-determined prices. There is emerging consensus among policymakers that competitive power markets are needed to lower the cost of providing electricity and improve the allocation of resources. This has been the case in other countries that have opened their power markets to competition:

- In Argentina the availability of thermal generation capacity increased from 47 percent in 1992 to more than 75 percent in 1997. In just three years the supply of electricity jumped 40 percent and wholesale electricity prices fell more than 30 percent.
- In England and Wales fuel switching and increased efficiency cut real fossil fuel costs per unit of electricity generated by 45 percent in the five years following the 1990 restructuring.

Between 1990 and 1997 real electricity prices fell 22 percent.

- In Australia electricity bills dropped 26 percent among 410 large consumers (those consuming more than 750 megawatt-hours a year) surveyed in New South Wales and Victoria.
- In Bolivia the average price of bulk power fell by nearly 20 percent between 1996 and 1999.

Introducing competition in China would increase efficiency and reduce costs in several ways. The variable cost of production would decrease as a result of competition for dispatch. Resource allocation would be optimized because new investments would be guided by market prices and participants would be allowed to choose new technologies. The threat of new entry from transparent wholesale market prices would force power companies to be more strategic in their investments and cut their operational costs. And contracts between generators and purchasers would become more efficient, because market prices facilitate more efficient risk sharing.

Three factors facilitate the introduction of competition in China's power sector:

- The excess capacity in many provinces offers a window of opportunity for introducing competition among generators because it minimizes the potential for price surges—which are more likely when competition is introduced amid capacity shortages. (However, introducing competition among generators amid capacity shortages will expedite new generation investment and allow the shortages to be removed faster than would otherwise have occurred.)
- Under prevailing tariff policies and decentralized distribution, the prices paid by users cover (and in some cases exceed) supply costs. As a result retail competition, coupled with effective regulation, would not lead to unacceptable price increases—which have helped derail power reform in other countries.
- The government recently lifted a ban on the use of natural gas for power generation. New technologies, such as gas-fired combined cycle stations, could increase investment and operational efficiencies.

Moving toward Competitive Markets

The size of China's power sector, its organization along administrative jurisdictions, and the policy of self-reliance have led to a multilevel system based on administrative boundaries. Distinct entities operate at the subprovincial (municipal, prefecture, and county), provincial, interprovincial, and national levels. At the subprovincial level alone there are about 200 municipal (or prefectural) and more than 2,000 county power entities. In addition, there are 32 provincial systems based around 14 regional networks on the mainland, only some of which are interconnected (map 1.1).

The strategy

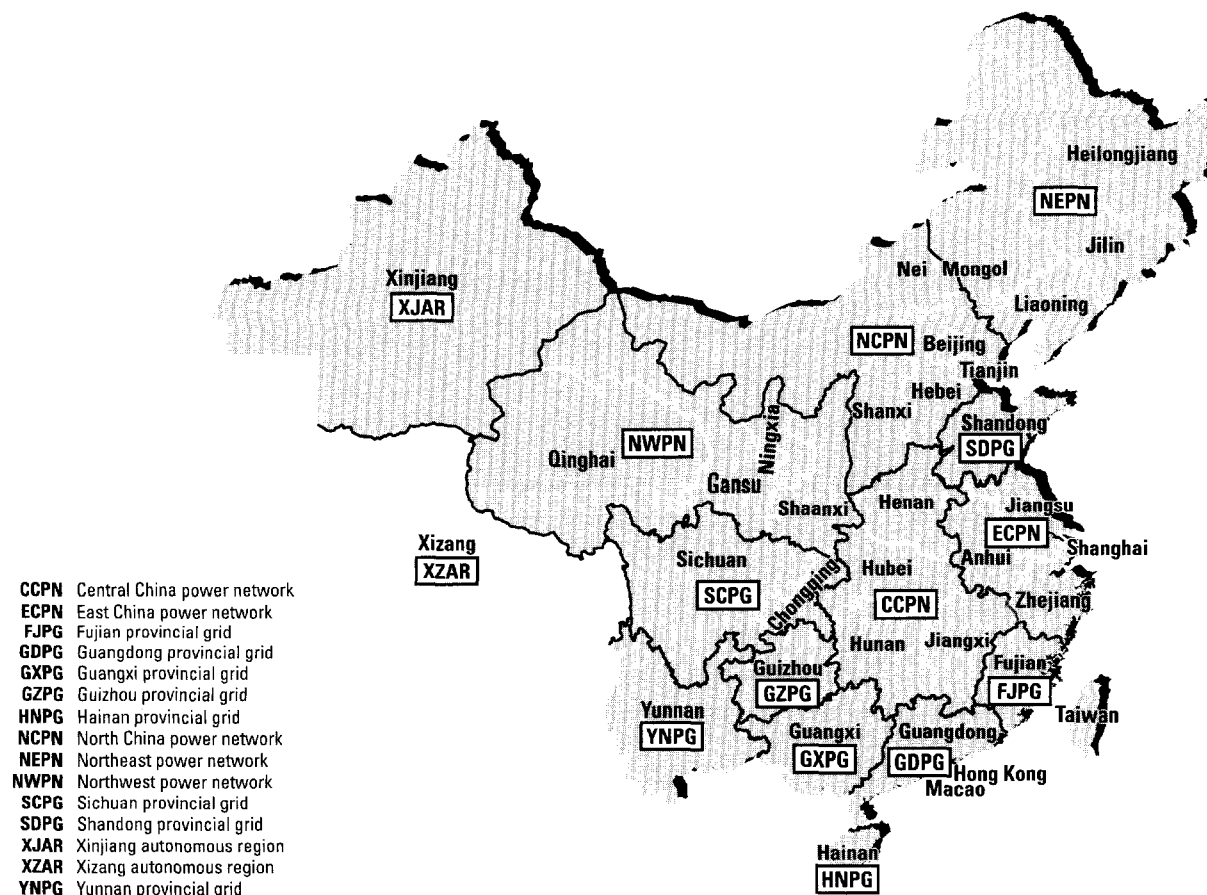
Given this geographic scope and diversity, the proposed strategy for developing competitive power

markets is based on parallel implementation of competitive power pools at the regional or provincial level, along with a scheme for voluntary bilateral power exchanges between competitive power pools. To facilitate the gradual integration of competitive power pools into larger markets, common national principles would be adopted for competitive market and transmission rules. The objective would be to establish competitive pool markets that are as large as possible.

Regional or provincial market development would be initiated with competition between generators in an energy pool, and gradually evolve to wholesale competition. Bilateral power exchanges between these competitive pools would increase the scope of competition and should be considered a first step toward integration. In essence, the energy pools at the regional

Map 1.1

China's provincial and interprovincial power networks



Source: State Power Corporation of China

or provincial level represent a more advanced form of market relative to the bilateral market for power trade between pools. The competitive energy pool in operation in Zhejiang province and the energy broker under development in the East China power network are examples of these two approaches.

In pursuing this strategy, the first task will be to define the scope or size of each competitive pool market. Two general principles are useful:

- A competitive pool market must have one set of rules governing its operation—different rules mean different markets. This principle sets an upper limit on market size. But even if all of China had one set of rules, it would not mean that it could be organized as one market.
- A competitive pool market will cover an area where generators and wholesalers are physically interconnected and coordinated by a central control room. The central control room will receive bids, create dispatch schedules, issue dispatch instructions, establish the market price for each trading period, and include flows over interconnections between its area and adjoining areas. This principle sets a lower limit on market size because it makes no engineering sense to have two central control rooms in an area with few transmission constraints. But there can be, and often are, subsidiary control rooms within an area.

In practical terms, a competitive pool market can cover two or more provinces that are interconnected, using one central control room provided the rules are the same. It would also be possible—but perhaps not practical—to include in the same market two or more provinces that were weakly interconnected. If they were not interconnected at all they would be separate markets in an economic sense, since they could not affect each other. The size of the competitive market will depend on the ability to reorganize the companies within the area—the smaller the area, the quicker this will be accomplished. But the larger the area, the more players there will be, and the greater the potential for effective competition between participants.

To ensure a consistent approach to competitive market implementation, both for energy pools and bilateral trading schemes, a national policy should be published that outlines market

development principles, defines responsibilities at different market levels, and lays out the implementation strategy. This policy should be published as soon as possible. The guiding principles for this policy are outlined below.

The guiding principles

Developing competitive power markets in China will require changing the structure of the industry, diversifying ownership, and transforming institutions. New sellers and buyers of power must be formed from today's integrated enterprises—most of which are directly or indirectly owned by the State Power Corporation of China (SPCC). Institutions and processes are needed to regulate the monopoly segments of the industry, supervise market implementation and operation, and liberalize fuel markets. As with past reforms in the power sector, a phased approach is considered prudent for several reasons:

- *Competition must keep pace with other reforms.* Efforts to restructure and introduce competition in the power sector must be aligned with broader macroeconomic reforms as well as reforms in other sectors. Restructuring state enterprises and implementing social safety nets would ease the burden of liberalized electricity prices for uncompetitive enterprises and their employees. Financial sector regulations should allow active futures trading in electricity so that participants can manage their supply risk and market exposure. While bilateral contracting between participants is possible under current regulations, the creation of a secondary market in electricity would require new regulatory guidelines.¹ Liberalization of fuel and transportation markets would enable generators to manage their fuel price risk and seek cost efficiencies in fuel purchases.
- *Distributors must become more commercially oriented and acquire risk management skills.* Although distribution companies are decentralized and generally profitable, they lack the capacity to deal with power sellers in a competitive market—and they cannot manage market risk. But commercialization is a key element of the government's infrastructure reform policy, and there are plans to restructure some distributors as independent corporations by 2002.

- *Regulatory skills need to be developed.* Effective competition requires effective regulation. It generally takes a few years for regulators to perform their jobs well. Although regulatory institutions have been established at the central level and identified at the provincial level, it will take time to implement appropriate regulations and develop skilled personnel.
- *Transmission bottlenecks need to be eased.* Adequate transmission infrastructure is needed to connect buyers and sellers and facilitate competition. Inadequate transmission can drive up prices or make economic trades impossible. A phased approach to increasing competition would allow provincial and interprovincial power utilities to expand transmission connections.
- *New management skills take time to develop.* New market conditions will require new management skills in generation and distribution. Experience in other countries has shown that exposure to competitive market trading is needed to develop these skills. Management expertise is also required in the use of new systems for communication, information management, billing systems, trading, and system control. Attempts to build competitive markets without developing the required skills can lead to failure, delaying reform.

Key requirements for increasing competition include:

- *Phased market access for retailers and consumers.* Although competition between generators is important for increasing efficiency, huge gains will also come from the efficiency pressures exerted by retailers (distributors) and later by consumers. Although the government's objective is to introduce competition gradually, retailers and consumers should increasingly be allowed to choose their own suppliers. The timing of and policies to implement this access should be determined by the regulator.
- *Incentives for bilateral power exchange between competitive markets.* The implementation of competitive pool markets at the regional or provincial level and mechanisms for bilateral trade between them will automatically increase trading if the interfaces between the markets are efficient and there are incentives

to trade. To overcome the existing weak incentives for bilateral trade, market rules and supporting regulations must ensure that regional or provincial single buyers have incentives to purchase the cheapest supply from sources within or outside the competitive market area. Bilateral trade will be promoted through consistent rules for market operation, electricity trade, transmission access and pricing, and quality of service regulation.

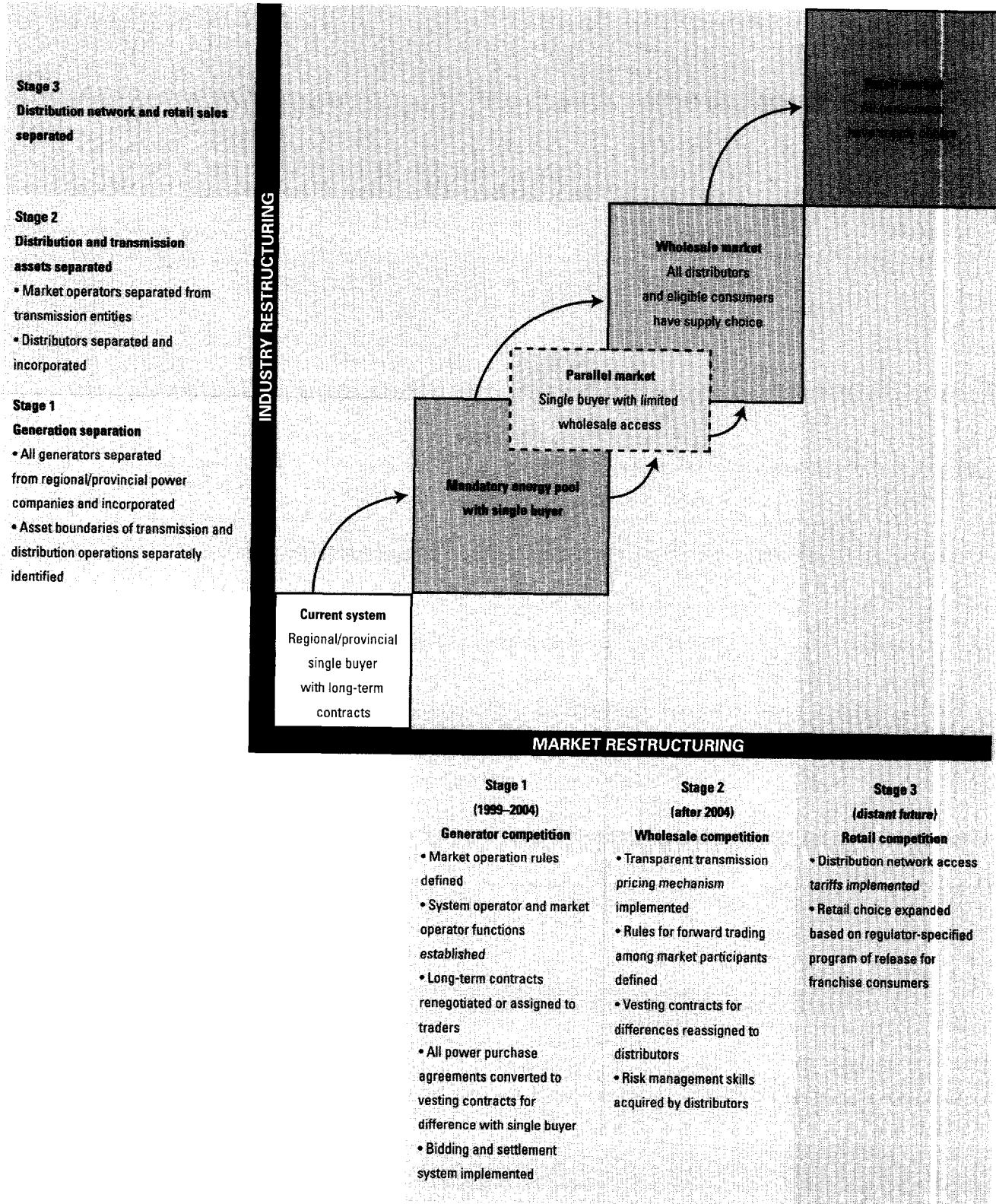
- *Consistent transmission pricing.* Consistent transmission pricing should be adopted to facilitate trade and the expansion of transmission networks within and between competitive market areas.
- *Diversified ownership.* Competitive markets require multiple unrelated buyers and sellers—particularly at the generation and wholesale levels. The creation of many separately owned generation companies should be a priority.
- *Market-determined end-use tariffs.* A competitive market cannot work if end-use consumer tariffs are regulated in a way that does not recognize that generation prices—and later wholesale prices—are determined by market forces. While it is important that transmission and distribution revenues be regulated, it is also important to allow the pass-through of competitively incurred electricity purchase costs, because the benefits of competition can be passed on to consumers only if lower costs are translated into lower prices.
- *Fewer barriers in fuel supply markets.* Generators can compete effectively only if they have control over their fuel purchase costs. Thus it is important that national competition policy address the liberalization of coal and gas markets, so that generators have access to flexible and competitive fuel prices.

Stages of reform to implement competitive pools at the regional and provincial levels

This report proposes a three-stage restructuring of China's regional and provincial power systems (figure 1.1). In the first stage, all generators compete to sell their output to a mandatory energy pool operated by the regional/provincial single buyer. In the second stage, competition at the wholesale level is introduced, allowing

Figure 1.1

The three-stage competitive market transformation of China's power sector



distributors and eligible industrial consumers to participate in the market. In the third stage, retail competition is introduced, allowing all consumers to participate in the market.

The phased approach allows a smooth transformation by building the skills and institutional capacity needed to manage, operate, and regulate wholesale and retail competitive markets. It also allows implementation to begin immediately, without waiting for broader economic reforms and industrywide restructuring to be completed—in other words, market implementation can be undertaken in parallel with supporting economic reforms. Finally, a phased approach allows provinces to move at different speeds depending on their ability to build the needed skills and capacity.

Stage 1: creating a mandatory energy pool with a single buyer

Stage 1 is the main step in developing competitive power pools at the regional or provincial level. During this stage the main objective is to have generators compete to sell energy into an energy pool. Participation in the pool is mandatory—all generators must submit price bids in order to be dispatched. The regional or provincial power company will continue to be the main purchaser (single buyer) of all capacity and energy. But the role of the power company will be limited to power purchases, transmission, system and market operation, planning, and some distribution operations. All generators will be separated from the power company and established as independent companies. A mandatory energy pool with a single buyer market has been in operation in Zhejiang province since January 2000.

The reform benefits in stage 1 will come from the competition among generators, which will cut their operating costs and achieve economic dispatch. Although the single buyer will initially buy a significant portion of each generator's output, generators will have incentives to minimize their costs and to bid as low as possible in order to be dispatched.

Stage 1 institutionalizes key market features such as a framework for generator price bids, transparent market rules, financial contracts for differences (see annex), and system and market operator functions (see chapter 2). This stage

develops the basic skills for managing contracts for differences, negotiating such contracts, bidding competitively, dispatching against bids, and publishing pool clearing prices. These features are extremely important in establishing strong foundations for stage 2—the evolution to wholesale competition.

Although stage 1 is the most important phase of market development, it should be viewed only as a transitional stage. Once the mandatory energy pool with a single buyer is made operational—a process that will take a year or two in most provinces—the objective should be to move quickly to stage 2.

Stage 2: developing wholesale markets

Allowing distributors and eligible consumers to negotiate contracts for differences directly with generators expands competition to the wholesale level—marking an important shift in the nature of competition and risks for market participants. First, generators will no longer be required to have contracts for differences only with the single buyer—these contracts will be assigned to distribution companies. Thus the single buyer will no longer have to take on capacity risk, because this obligation will be passed over to the multiple buyers, who must now purchase at the pool clearing price in order to meet consumer demand. Second, there will be competition between generators and distributors to negotiate the best possible contracts for differences in order to reduce price risk exposure to the volumes purchased on the spot market. International experience indicates that such competition can be a powerful mechanism for holding down costs and prices. The benefits to consumers can be substantial—as consumers in Argentina, Australia, Bolivia, Chile, England and Wales, and Norway have realized.

During stage 2, transmission assets will be completely separated from generation and distribution assets. The regional or provincial power company will become a transmission entity that is regulated to allow third-party access to the transmission network.

Wholesale competition can be introduced in two ways. Full wholesale competition can be permitted from the start, with all distributors and eligible large consumers allowed to participate in

the market directly. Alternatively, the single buyer can gradually reduce its share of the market while allowing more distributors and large consumers to buy directly from the energy pool and to negotiate contracts with generators. This approach is similar to the gradual third-party access being implemented in several European countries. Access to distributors and large consumers should be allowed as soon as they can acquire the skills to manage demand and purchase risk and negotiate flexible forward supply contracts.

Stage 3: introducing retail competition

The third stage in the transition to competitive markets is to introduce retail competition. At this point all end users will be able to choose their electricity retailer. Allowing consumers to purchase electricity from any retailer puts pressure on retail margins, encouraging retailers to purchase wholesale electricity as cheaply as possible and to reduce other operating costs.

Only a few countries—New Zealand, Norway, the United Kingdom—have reached this stage of market development. Before retail competition can be introduced, the business of distribution (managing the wires business) must be separated from the business of retailing (trading electricity as a commodity), so that alternative retailers can compete with distributors. In addition, policies that support efficient processes for the transfer to consumers from one retailer to another must be developed and transfer systems implemented.

Bilateral power trade between competitive markets

A mechanism for bilateral power exchange is needed to promote trade between competitive power pools, to reap the benefits of differences in generation costs, resources, and load patterns. An institution that covers several competitive power market areas should be established to implement the power trading scheme and coordinate the bilateral power exchanges. (See chapter 3 for a detailed discussion of the bilateral power trading scheme.)

Before the establishment of a centrally dispatched mandatory energy pool that integrates smaller competitive pool markets, a bilateral

exchange of power between the competitive markets can be introduced to accommodate differences in the evolving competitive pools and to extract efficiencies prior to moving to a wider geographic competitive power pool. Participants in these regional and provincial competitive markets should be allowed to independently negotiate bilateral contracts for all long-term (one year or more) and short-term (seasonal, monthly, weekly, daily) energy and capacity transactions contracted at least a day ahead. Spot energy (hour ahead) transactions should be based on transparent price bids, and these transactions could be managed by an energy broker. The energy broker could be part of the interregional institution.

Initially, bilateral power trading will be between single buyers in adjoining competitive regional or provincial markets. These markets may be at different stages of development—some may be operating competitive generation pools, others might have moved to wholesale competition, and others may not have done much at all. As wholesale competition is introduced in these competitive regional and provincial pools, generators and distributors may be given the opportunity to trade across the boundaries of the competitive pool area. This will gradually lead to stronger integration of these competitive pool markets.

Because bilateral trading is based on voluntary trading, as opposed to mandatory participation in the competitive pools at the regional or provincial levels, it will be necessary to ensure that incentives are in place to promote trade and to expand transmission capacity between the competitive pools.

Note

1. A secondary market allows futures contracts to be traded by buyers and sellers of electricity. For example, a consumer with a financial contract to purchase a specific quantity of energy at a particular price on a specific date has the option of selling the contract to another party. That is, the consumer is not required to take delivery of the contracted energy. Similarly, the generator does not actually have to generate power to meet the contract obligation but may instead sell the obligation to another generator.

Chapter 2

Developing Competitive Pool Markets

Under the three-stage transformation proposed in chapter 1, regional and provincial power systems will be the first level where competition is introduced in China's power sector. This chapter focuses on the market design, asset restructuring, changes in responsibilities, and other reforms needed for each stage of competitive market development—from competition among generators to wholesale competition to retail competition.

Transforming the Regional and Provincial Power System

Regional and provincial power companies are at the center of the proposed reforms. These power companies will first have to separate (or “unbundle”) all generation, then separate distribution when wholesale competition is introduced. Multiple generators and distributors will be needed for effective competition. Existing functions, such as the power purchasing function, will have to be modified. And new functions, such as trading and market operations, will have to be established.

The current structure

Although their structures differ, all of China's regional and provincial power systems share key features (figure 2.1):

- Ownership of generation facilities is diverse. Although many power stations connected to the transmission grid are wholly or partly

owned and managed by the regional (or provincial) power company, independent (nonutility) power producers provide a large share of generation in some provinces. In addition, most regions and provinces have many small generation plants embedded in the distribution network. These embedded generators may be owned by the distributors (power supply bureaus) or by independent power producers. The plants connected to the transmission grid may be referred to as main grid generators, to distinguish them from the smaller embedded generators. The power company holds power purchase agreements with the main grid-connected independent power producers. The embedded generators are usually dispatched by the distributors, although their production schedules are agreed to in advance by the regional or provincial power company.

- The transmission grid is owned and operated by the regional (or provincial) power company. No uniform distinction is made between transmission and distribution networks.
- Distributors supply power to monopoly franchise areas. These areas are typically defined by administrative boundaries (municipality, prefecture, or county). Ownership of distributors is diverse. They may be owned by the provincial government, the local (county or municipal) government, or the regional or provincial power company. Distributors owned and managed by the regional or provincial power company normally operate as cost centers; other

power supply bureaus are structured as independent government-owned entities. In general, the share of distribution managed by the power company is larger in urban than in rural areas. Rural distribution is highly decentralized and disaggregated, with township and village communities and cooperatives often assuming responsibility for maintenance, billing, and collection.

- The regional or provincial power company is responsible for planning the expansion of generation and transmission. It forecasts consumer demand, prepares investment plans and annual budgets, and recommends retail tariffs and independent power producer payments to the government. The provincial pricing

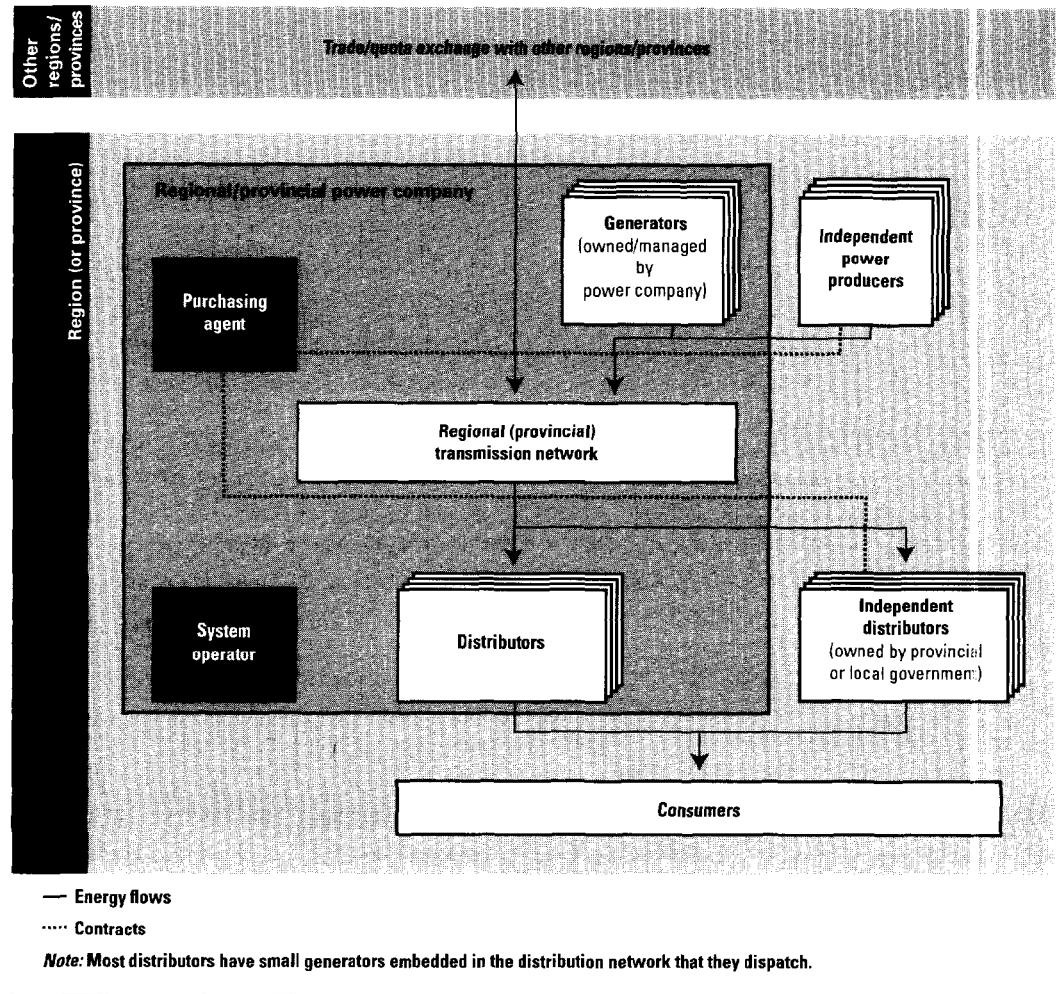
bureau reviews the tariff recommendations to ensure consistency with government guidelines. Final approval is given by the State Development and Planning Commission.

- Power companies carry out a range of other business activities, including construction and fuel procurement.
- Energy and capacity exchanges between provinces (or regions) are normally coordinated and managed by a regional (or national) power entity, such as the regional power group (or State Power Corporation of China).

The post-reform structure

As regional (or provincial) competitive pool markets are implemented, the structure of the power

Figure 2.1
China's regional/provincial power system



system will be completely transformed. By the end of the transition:

- *The regional (or provincial) power company will operate an open access transmission system with no ownership stake or operational role in generation and distribution.* The company will retain ownership and operational responsibilities for the transmission system, the system operator, and the market operator within the competitive market area. As responsibilities shift to electricity traders and retailers, the power company's planning role will shift from bearing responsibility for comprehensive system planning to providing information that independent market participants can use to make investment decisions (indicative planning).
- *Ownership of generation will be further diversified, and all ownership linkages between generation and transmission will be severed.* Joint ownership of generation and distribution will be limited. No single entity will be allowed to own or operate more than a quarter of the installed capacity within the competitive market area in a region or province. All generators will have open access to the transmission and distribution network, and pricing will be fair and transparent.
- *Generators will be required to bid into the mandatory energy pool.* Generators will sell their power through a combination of spot market sales and financial contracts (contracts for differences). Wholesale and retail consumers will be able to negotiate financial contracts to manage price and demand risk with competing generators.
- *Distributors will be set up as separate companies.* In addition, as the transition to retail competition is made, the distribution network function will be separated from the consumer retail supply function. New operators could be expected to emerge to supply the retail market.
- *System and market operator functions will be established.* The dispatch function will be transformed and expanded to include the system and market operator functions, which are essential in a competitive pool market.
- *An energy broker will be established to facilitate contract and spot power trades between competitive regional and provincial pool markets.* Initially,

these trades will be between single buyers. Generators and consumers in one market could eventually be allowed to trade with generators and consumers in other markets.

- *Fuel supply markets will be liberalized and no longer be a function of regional or provincial power companies.*

As the market transition proceeds, regional and provincial power companies—with their restructured functions restricted to transmission and system and market operator functions—may no longer need to be companies in the legal sense. It is possible that regional and provincial power entities will be made a branch of the National Transmission Company (see chapter 4).

Evolution of essential functions

A competitive power market will require modifying functions and creating new entities to perform them.

Purchasing agent

In the single buyer structure, one purchasing agent—the regional or provincial power company—has the exclusive right to purchase power, with the associated responsibility of ensuring adequate capacity to meet demand (although this function is not separately identified; see figure 2.1). In competitive markets, purchasing agents (or traders) aggregate consumer demand and arrange contract and spot purchases to meet that demand. As the market transition begins, the purchasing agent function should be assigned to a separate unit within the restructured regional or provincial power entity. This unit will initially be responsible for negotiating contracts for differences with generators and ensuring adequate installed capacity to meet energy demand.

As the transition to wholesale competition begins, the purchasing agent's responsibilities will decline as distributors and consumers begin negotiating their own contracts. The purchasing agent's role in ensuring adequate installed generation capacity will also decline with increasing reliance on the market. The transition to wholesale markets will also require that the initial contracts for differences be transferred to distributors and large consumers, eliminating the need for the purchasing agent within the power entity.

System operator and market operator

All competitive power markets require the functions of a system operator and a market operator. The system operator performs crucial functions. Some of these functions—dispatching the system and managing grid constraints, coordinating generators to balance supply and demand, maintaining system stability and reliability, coordinating maintenance for generation and transmission—are currently performed by the dispatching bureaus of regional and provincial power companies. These functions will remain unchanged as competition is introduced, but new responsibilities will be added. The system operator will also have to ensure that the market-determined dispatch schedule, based on generator bids, is carried out as efficiently as possible without disrupting the physical stability of the system. To do so, the system operator can require market participants to produce or consume energy and provide reactive power or reserves in a way that may diverge from that indicated by the market operator.

The market operator's function is entirely new, unique to competitive energy pools. The market operator is responsible for matching supply and demand bids, preparing a pre-dispatch schedule, calculating financial settlements, monitoring the market, and administering market rules, including rules on market participation and bidding. The functions of the market operator and system operator are described in table 2.1.

The system operator and market operator may remain as part of the transmission entity (that is, the regional or provincial power company after restructuring) as long as that entity has no own-

ership linkage with any generators in the market. A combined system operator and transmission entity is generically referred to as the Transco model. It is also possible to separate the system operator from the transmission entity—referred to as the ISO-Gridco model. The advantages and disadvantages of the two models are discussed in chapter 4. Given the government's policy of fully separating generation from transmission, it is recommended that (at least initially) the system operator and market operator be organized as a separate unit within the regional or provincial power company.

Transmission

Although transmission-related functions of operation, maintenance, ownership, and expansion are not new, they should be recognized as separate functions early in the restructuring process. The clear accounting separation of transmission functions will facilitate the development of a transparent mechanism to determine transmission costs and implement a workable transmission tariff scheme. By extension, this will also allow the implementation of a credible open access regime. Operational responsibility for the transmission network would rest with the system operator.

Planning

The planning function, currently handled by regional or provincial power companies, consists of preparing load forecasts, carrying out least-cost expansion plans for generation and transmission, and identifying needs for new transmission capacity. The entity responsible for meeting

Table 2.1

Functions of the system operator and market operator

Function	System operator	Market operator
Central function	<i>Physical:</i> Dispatches power and maintains system security under the direction of the market operator. To ensure the security of the system, the system operator is allowed to direct market participants to produce or consume more or less energy and to provide services that may diverge from the market-determined solution	<i>Financial:</i> Obtains bids, determines pre-dispatch, directs dispatch, handles financial settlement of the market
Administrative function	Administers security and operating rules (often formalized in the grid code)	Administers market rules
Supply and demand function	Matches supply and demand of power in real time, in accordance with market dispatch instructions	Matches supply and demand of bids before power is dispatched

power demand should also be responsible for planning system expansion to meet that demand. In stage 1 this obligation rests with the purchasing agent; hence the entire planning function will continue to be performed by regional or provincial power companies.

As wholesale competition is introduced in stage 2, elements of the planning function, such as preparing load and demand forecasts, will remain with the market operator so that it can perform supply and demand clearing responsibilities. These elements will pass separately to distribution companies, which will have to strengthen their forecasting capacity in order to carry out these functions. As reform proceeds, centralized system expansion planning will give way to indicative transmission planning, with increased reliance on market pricing to ensure that adequate transmission capacity is available to meet energy demand.

Introducing Competition in Stages

Extensive restructuring and preparation will be required before and during each stage of the move to competitive markets. An important challenge will be equipping managers and system operators with the skills needed in competitive markets. This process takes time. The transition from one stage to the next should be carefully managed by regulatory institutions with a clear mandate to introduce and expand competition in the power sector.

Stage 1: the mandatory energy pool with a single buyer

As noted, during stage 1 all the main grid-connected generators will compete by bidding into the mandatory pool, and all output will be purchased by the regional or provincial single buyer at the market clearing price, complemented by contracts for differences. Contracts for differences are an efficient way for generators and the single buyer to hedge their risk against fluctuations in prices and market demand (see the annex). But if the contracts are not adequate to cover rising demand—which is likely—the single buyer would be exposed to price risk. For this reason stage 1 is considered a transitional stage that allows an orderly transition to multiple buyers (stage 2).

The combination of the mandatory energy pool with a single buyer is a novel way to introduce competition at the generation level before expanding competition to the wholesale and retail levels. The mandatory pool is an appropriate way to introduce competition in an environment where most large consumers and distributors lack the capacity to engage directly in the market—because they are restricted by law, have limited management skills, or have almost no skills to manage power purchase risks in a competitive market. A mandatory energy pool is the preferred choice for the initial transition to competitive markets in China; the reasons are explained in box 2.1. Some features of this approach are derived from the transitional market arrangements used in New South Wales, Australia. The approach is being successfully piloted in Zhejiang province.

In China the mandatory energy pool with a single buyer is expected to:

- *Increase efficiency by achieving economic dispatch of generating plants.* Each generator will bid a price and quantity for a specific period in the future. A merit-order bid stack—in which generators are dispatched on pure merit order—and dispatch schedule will be prepared to meet expected demand.
- *Strengthen incentives for generators to maximize availability and cut operating costs.* While most of the electricity purchased by the single buyer will be covered by the initial contracts for differences, a limited amount of additional energy will be purchased at the market-determined spot price. Generators will have an incentive to compete to deliver this additional quantity, which offers profit opportunities.
- *Generate a transparent spot market price, providing generators and the single buyer (and later wholesalers) with public information on price volatility and risk.* This information will help market participants develop efficient risk management strategies by allowing them to determine how much spot market exposure to take on. The spot market price also informs potential investors about the potential profitability of the market (with a very low spot price indicating excess capacity, and a higher spot price the potential for profit). In addition, the spot market provides regulators with insights into

Box 2.1

Why the mandatory energy pool is the only option for developing competitive power markets in China

Competitive power markets can be broadly separated into mandatory (or gross) or voluntary (or net) pools. In a mandatory pool, responsibility for system organization is centralized and all electricity is traded through the pool. Through bids and contracts, the system operator obtains all the information needed for scheduling and for ensuring reliability. Bidding rules require that quantities and prices be specified. Generators can offer their output at any price, but they are required to produce the quantity that the system operator indicates. Mandatory pools are used in Argentina, Australia, and the United Kingdom.

In a voluntary pool, trades are made through bilateral contracts, and the pool is used to reconcile minor imbalances between supply and demand. Generators can either offer a price or declare the quantity of energy they propose to generate to the system operator. Market participants are self-scheduling, with the system operator simply coordinating the schedules that market participants declare. The system operator also deals with transmission constraints and ensures that supply meets demand. Voluntary pools are used in California and in Nordic countries.

For several reasons, a mandatory energy pool is the only choice for regional and provincial power market development in China:

- A voluntary pool is based on generators' access to consumers and requires that distributors be separated into independent companies. These conditions take time to develop and are expected to occur only in the later

stages of reform. The mandatory pool allows competition in generation to be introduced without waiting for separate distributors.

- A mandatory pool is based on a centralized dispatch mode, which is similar to current practice. It is prudent to develop the market within well-understood operating practices, and phase in changes in line with the development of institutional capacity.
- Stranded asset costs can be recovered more easily under a mandatory pool, by applying a uniform levy on all power transacted through the central market settlement process.

Choosing a mandatory energy pool does not prevent regions/provinces from eventually moving to a voluntary pool. For example, the United Kingdom is contemplating changing from a mandatory to a voluntary pool. Such a change would require renegotiating the contracts between generators and consumers. Contracts for differences between buyers and sellers, which are based on a price in the mandatory pool, would need to be replaced by new physical (or supply) contracts or other bilateral financial contracts. In addition, a procedure would need to be established in which generators provide the system operator with information on their dispatch schedules. And the bidding procedure would need to be changed from one in which all available electricity is bid to one in which only increments and decrements to the planned schedules are bid.

the possible exercise of market power by generators, allowing remedial measures to be taken. (Market power is defined as the ability of generators to raise prices above competitive levels and maintain those prices for a significant period. Methods of addressing market power concerns are discussed in chapter 5).

But these benefits could be limited, and the single buyer could become exposed to excessive price risk if competition is not extended to the wholesale level—that is, by allowing distributors and large consumers to buy directly from gener-

ators. Thus stage 1 must be viewed as a transitional stage during which market skills and supporting regulatory and supervisory institutions are developed before wholesale competition is allowed. It will be the task of the regulator and other state institutions to ensure that stage 1 is completed as quickly as possible. Regulating the activities of the single buyer is second best to introducing competition; multiple buyers must be allowed to participate in the market as soon as possible to create conditions for true competition.

Preparing for stage 1

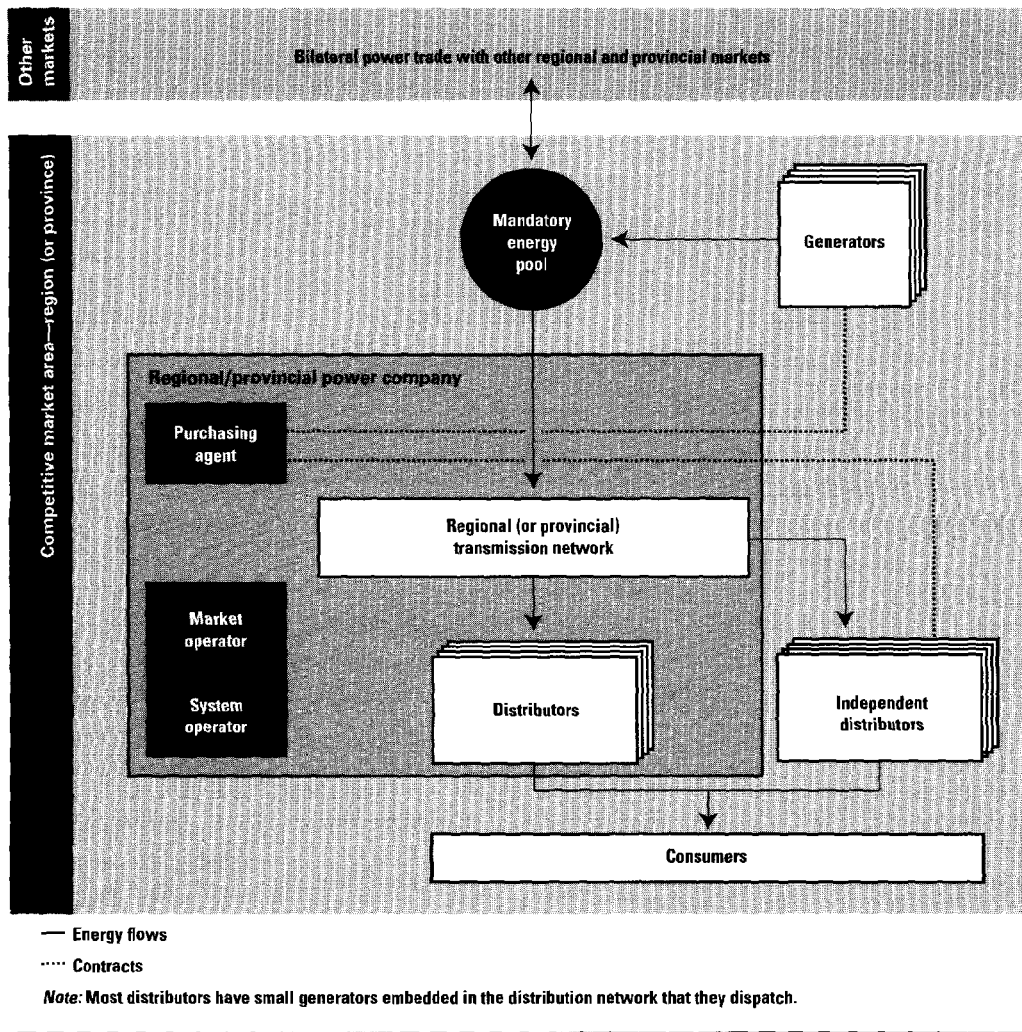
Several restructuring steps are required to prepare for the stage 1 market (figure 2.2). Although all parts of the regional and provincial power industry will be affected by the reforms, generators and power companies will see the greatest impact. Initial reforms should involve:

- *Preparing market rules.* Market rules will govern agreements and transactions between participants in the mandatory energy pool market. These rules should cover principles and rules for system operations, procedures for bidding, mechanisms for determining market energy prices, pricing mechanisms for ensuring adequate generation capacity, contracting rules

for contracts for differences, pricing mechanisms for transmission and ancillary services, principles for transmission access, rules for system security, and metering standards and codes. Given the importance of the market rules, all market participants should be involved in their preparation, and extensive training should be organized for all industry personnel. The market rules should be harmonized and supervised by the national regulator to allow integration of neighboring markets and gradually expand competition.

- *Restructuring generation.* All generators need to be separated from regional or provincial power companies (the future transmission

Figure 2.2
Stage 1: The mandatory energy pool with a single buyer



entities) and incorporated under the Company Law, because any link between the two would likely be perceived as potentially anti-competitive. While the separation process could begin with complete management separation from the regional and provincial power entities, it is essential that full ownership separation be the ultimate objective.

The restructuring of generation assets must ensure that individual generators are not able to exercise market power (see chapter 5). Initially, where possible, single plant (or station) generating companies should be formed. A detailed study will be required in each competitive market area to ensure that none of the generation companies to be created have market power. To the extent possible, decisions to merge multiple plants into single companies should be made only after the market begins operations, giving the regulator time to assess the implications of merger decisions that might undermine competition.

System stability concerns often lead to arguments to keep some or all hydroelectric generators integrated with the entity responsible for system operations. International experience has shown that this is not necessary. If there is a preference to maintain a few hydroelectric generators as part of the system operations entity, those generators should not be allowed to participate in the competitive market, as they could seriously distort the market and handicap its development.

- *Converting power purchase contracts to financial contracts for differences.* Contracts for differences are needed to make the transition to flexible financial arrangements consistent with mandatory participation in a competitive energy pool. Contracts for differences enable market operators to determine dispatch based on competitive bids while guaranteeing generators minimum revenue (see box 2.2 and the annex).

Existing power purchase agreements with privately owned independent power producers could be handled in two ways. First, independent power producers could be encouraged to change the form of the power purchase agreement to one that allows payment based on the pool energy price combined with a contract

for differences. If agreement cannot be reached with the independent power producer, the power purchase agreement would need to be assigned to a market trader, who would also hold a contract for differences for operations in the new market environment. In essence, the market trader would be responsible for honoring the power purchase agreement with the independent power producer, bidding the generator's output into the pool, and obtaining compensation based on the contract for differences and spot market sales of energy. (The renegotiation of contracts and the role of the market trader are addressed in chapter 4.) Contracts based on administrative quotas and prices will need to be restructured into suitable bilateral contracts that do not distort competition in the market.

- *Establishing system and market operator functions.* As noted, system and market operator functions are essential for competitive power markets. System operator functions will be an extension of existing dispatch functions. Market operator functions are new and unique to competitive power markets. System and market operator functions could be combined as a separate unit within the regional or provincial transmission entity. This unit should be ring-fenced to prevent conflicts of interest in the dispatch of generation, which although separate may temporarily retain an ownership link with the regional or provincial power company during part of stage 1. To support these functions, information systems will have to be developed to manage generator bidding, scheduling, and market settlement processes.

Preparing for stage 2

The stage 1 market, with generator competition, should be only a transitional phase before wholesale competition is implemented in stage 2. To prepare for stage 2, the following steps should be taken during stage 1:

- *Restructure transmission.* The transition to stage 2 requires transparent transmission pricing and guidelines for open access to the network. Transmission must be set up as a profit center to prepare for its establishment as a separate entity in stage 2. Transmission assets must be separated from distribution network assets.

Box 2.2

Bidding and contracting arrangements in the mandatory energy pool

In the mandatory energy pool, all generation will be subject to central scheduling and dispatch based on bid prices, and all energy will be traded in the market. Participation in the market will be compulsory for all centrally dispatched generators. All generators must agree to operate in accordance with the market rules, which require them to submit price bids to the market operator.

Generator bidding

Each generator will be required to submit a bid price and bid quantity to the market operator before the generator's plant can be considered for dispatch. The market operator will stack all the bids in order of bid price, from lowest to highest (see figure). To balance supply and demand in real time, the system operator will dispatch plants into the energy pool based on the market operator's bid stack. The market (or pool) price—also known as the common clearing price—will be determined by the last generator dispatched to balance the total demand of the system. As demand fluctuates during the day, the common clearing price will change.

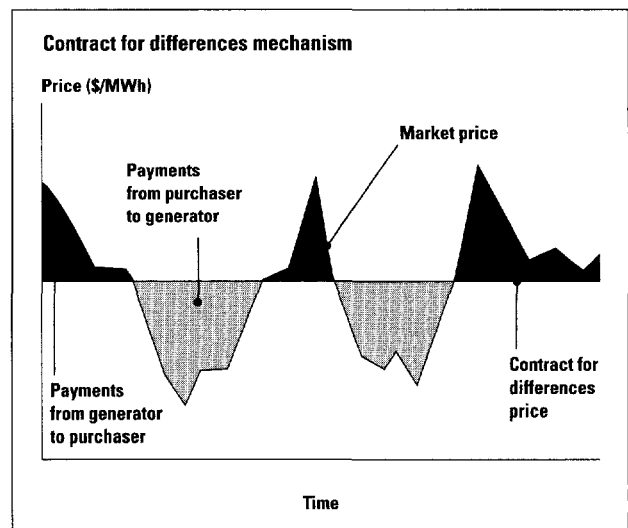
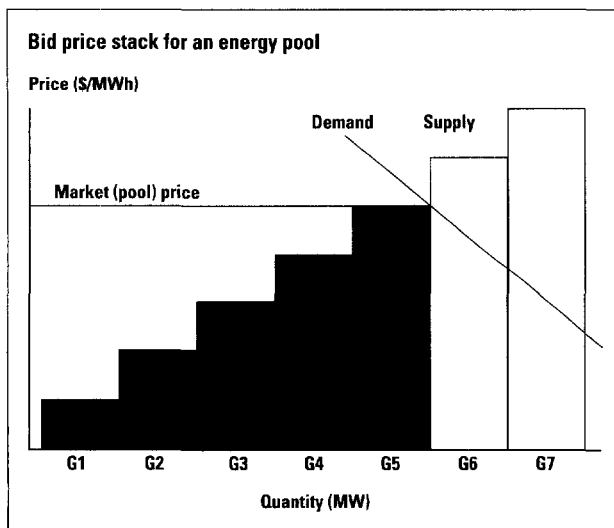
In most markets of this type, the trading period is half an hour, and generators need to submit 48 bids a day. (The length of the trading period will depend on metering capability.) The generation offer is submitted ahead of time, usually one day in advance. To provide flexibility in equating

supply and demand, generators are able to vary their price bids to the power company on a daily basis. Quantity bids can be altered more than once a day. To prevent manipulation of the market by generators at times of shortage (or system constraint), market rules could impose a pool price cap.

The contract for differences

The contract for differences is a financial instrument negotiated between the buyer and seller of electricity for an agreed quantity of electricity at a specified price (the contract price or strike price). The contract for differences market and the physical market are linked only by the common market clearing price. In the energy pool the generator of electricity always receives the clearing price, and the purchaser always pays the clearing price. With a financial instrument, if the market clearing price is below the contract's strike price, the purchaser pays the difference to the generator. If the clearing price is above the strike price, the generator pays the difference to the purchaser (see figure). This mechanism creates an agreed profile of prices for the contracted quantity of electricity for the duration of the contract.

Box 2.2 continues on page 26



Box 2.2 Bidding and contracting arrangements in the mandatory energy pool *continued*

In the initial stages of reform, when both generators and purchasers of electricity must adapt to competition, the “vesting” form of the contract for differences is a useful instrument for hedging price volatility for both parties. The vesting contract for differences enables system operators to determine dispatch based on competitive bids while guaranteeing generators a certain level of revenue (see the annex for a detailed description of how contracts for differences work). The generator receives the specified stream of revenue when the plant is available to meet contract obligations, although the generator may not actually be required to generate if energy can be obtained from a cheaper source within the pool. If the generator is not able to meet its obligations when required, there may be penalties.

In each trading period, each generator receives payments based on two components: energy produced and delivered to the pool and revenue provided by the contract for differences. The first component is determined by the actual dispatch volume and the common pool clearing price for each trading period. This may be represented as $V_e P_p$, where V_e is the actual energy produced and P_p is the pool price at which the market clears. The second component is the difference between the contract price (P_c) and the pool price (P_p) times the contract quantity (Q_c)—that is, $Q_c(P_c - P_p)$.

As generators compete for dispatch in the pool, the

revenue from pool prices is supplemented by revenue from vesting contracts for differences. Both sources of revenues fluctuate with the pool price, but total revenue remains relatively stable:

$$\text{total revenue} = (\text{energy produced} \times \text{pool price}) + (\text{contract quantity} \times \text{differential price})$$

or

$$\text{total revenue} = (V_e P_p) + Q_c (P_c - P_p).$$

The initial revenue coverage to be provided to generators through the vesting contract for differences is an intensely debated issue—one that is best resolved during market implementation. Because generators are faced with a completely new market and operating arrangement with no record of credibility and fairness, some experts believe that the single buyer may initially have to provide contract for differences coverage for 100 percent of the generator’s historical revenue requirements. Generators participating in the Zhejiang market have thus far been satisfied with a contract for differences that covers 85 percent of their historical revenue requirements—mainly because growing demand has allowed them to obtain revenues close to and in some cases in excess of their past revenues.

Cost accounting of transmission and distribution must be separated as well.

- Restructure distribution. During stage 1 all distributors should be formed into profit centers or independent corporations. Most provinces have 6–15 prefectural or municipal distribution bureaus and many more county power supply bureaus. In addition, there are hundreds of small retailers at the village, cooperative, and township levels. The challenge is determining the economically efficient composition of these distribution companies—normally measured in terms of the number of consumers, volume of electricity sold each year, and geographic scope of the franchise

area—while balancing tradeoffs between economies of scale, ease of regulation, and incentives for competition. Larger distributors are better able than smaller distributors to realize economies of scale. At the same time, there must be enough distribution firms to create the necessary competitive environment, and to develop efficient yardstick competition. Too many firms, however, can make the market harder to manage.

Countries vary widely in terms of the size and number of distributors. Norway, a country of 4 million people, has 230 distributors. England and Wales have 12 distributors; Chile has 36. In South America and some European

countries, distributors typically serve 2–3 million customers. In India each state (roughly comparable to a Chinese province) is considered able to support only three or four distribution firms.

China will have to develop its own size guidelines. Those guidelines should ensure that there is adequate horizontal unbundling to facilitate regulatory comparisons and that distribution entities are large enough to be financially profitable to owners and investors.

- *Develop staff skills.* Distribution company staff must develop the skills needed to negotiate contracts for differences directly with generators and efficiently manage their purchase risk. To that end, a capacity-building and training initiative should be launched during stage 1.

Strategies for regions that cannot immediately implement a mandatory energy pool

Regions (or provinces) that are, for exceptional reasons, not ready to move to competitive markets should be required to develop generation purchase contracts in parallel with the separation of generation from transmission and distribution. As a first step these contracts could be based on a two-part tariff structure.

Two-part contracts are normally structured with separate variable and fixed charge components. Together these components ensure that generators receive sufficient revenue to meet their financial needs. The regional or provincial system operator would use a merit order dispatch process, based on verifiable variable costs. Most of this cost would reflect fuel purchase costs. (For thermal plants it would include verifiable station heat rates; for hydroelectric plants it would include water use costs.) Variable operation and maintenance costs would also be included in the energy payment. Capacity payments would be based on predetermined daily generation curves, giving generators financial incentives to be available at peak periods. When generators meet the target capacity (as defined in the contract), all fixed charges would be covered. For operation above the target capacity, the generator would receive a bonus payment. For operation below the target capacity, the generator would be charged a penalty.

The single buyer with two-part generation purchase contracts will achieve economic dispatch but will not achieve the full benefits of generator competition, because the incentives for generator efficiency and cost minimization are not as strong as in a competitive pool. Good contracts can help pressure generators to be more efficient, but it is not easy to develop good contracts because generators almost always have better information than purchasers and have every incentive to push for easily achievable targets. Two-part contracts also impose a large administrative burden on the single buyer, which must obtain, audit, and verify declared cost components by each generator. Because capacity and energy costs are based on individual unit characteristics, generators have every incentive to inflate cost figures.

However, a single buyer structure with two-part contracts may be justified for provincial power systems that are weakly interconnected to (or isolated from) neighboring provinces and have a small number of generators or that are dominated by two or three large generators. In these cases the possibilities for creating price-based pools will be severely limited by market size and potential for generator market power, and the transition to price-based competition may not be feasible for several years. Longer transitions with a single buyer and two-part contracts may be needed in provinces that lack the information on generator operating costs and efficient operating profiles needed to develop credible contracts for differences, or in provinces where generation cannot be immediately and fully separated from the provincial power company. But it is crucial that these two-part contracts not be rigid life-of-plant contracts. Rather, they should contain clauses that allow them to be converted to contracts for differences once the conditions for establishing a competitive pool have been met.

Stage 2: wholesale competition

During stage 2, competition will be expanded through the development of a wholesale market open to distributors, independent retailers, and eligible large industrial consumers (figure 2.3). The common spot market clearing price, available only to generators in stage 1, will be made available to all wholesale and eligible large con-

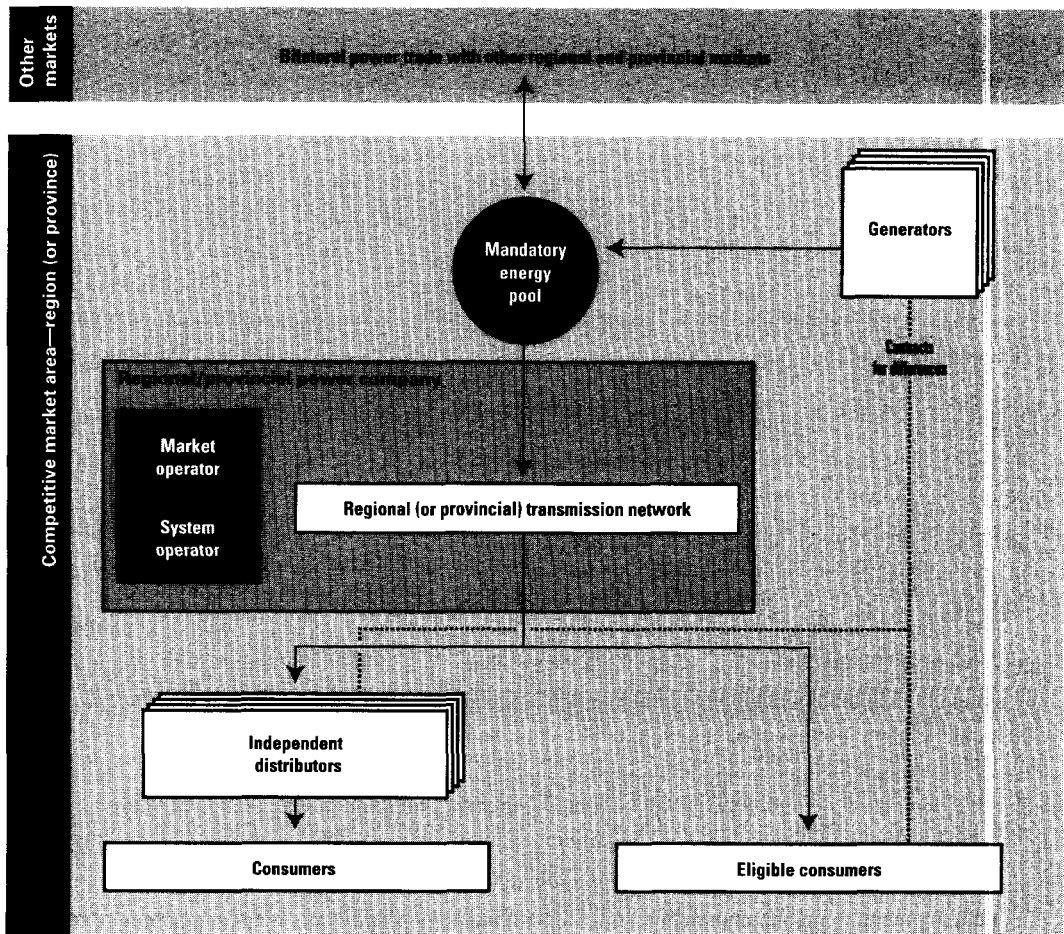
sumers, giving them a price signal to guide contracting for retail supply. As more buyers participate in the wholesale market, competition will increase. Buyers will have a choice of generators when setting up contracts for differences, and generators will have a choice of buyers.

To allow generators and distributors to manage their risks most efficiently and reduce the cost of this risk management, they should be allowed to trade contracts for differences in secondary markets. Such trading would be equivalent to futures trading in electricity, allowing generators and distributors to transfer their contractual obligations to other generators and distributors if there is mutual benefit to doing so. Secondary

market trading in electricity contracts would increase production efficiency and allow risks to be managed at the lowest possible cost, maximizing the benefits of competition to consumers.

The increase in competition could be partly controlled by gradually reducing the revenue coverage provided through the initial contracts for differences. As the coverage falls, wholesale buyers will seek to negotiate additional contracts with generators to manage future pool price risk, and generators will aim to assure a stable market for their output and sign such contracts with distributors. Competition would arise from their individual forecasts of demand and price in the energy pool and the desire of each participant to protect

Figure 2.3
Stage 2: Wholesale competition



Note: Most distributors have small generators embedded in the distribution network that they dispatch.

its short- and long-term financial position. It is for this reason that during stage 1, distributors should focus on developing skills in forecasting prices and system demand, as well as risk management.

To increase the confidence of participants and future investors in the stability and performance of the market, several additional steps need to be taken as part of the transition to stage 2:

- *Separate distribution from regional or provincial power companies.* The distribution profit centers and their subsidiaries should be separated and formed as companies. Each distribution company will retain responsibility for the distribution network and for the supply of energy to end users. Incorporated power supply bureaus will retain end users included in their franchise territory—with the exception of eligible large consumers, who will be allowed to contract and purchase their supply directly in the market.
- *Establish transmission assets as an independent entity, with no links to generation or distribution companies.* Regional or provincial transmission entities, which are likely to be subsidiaries of the National Transmission Corporation (see chapter 4), should be regulated to allow third-party access to the transmission network.
- *Implement transparent transmission pricing.* A transmission pricing scheme is needed that allocates transmission costs fairly among users and provides incentives for efficient system use (see chapter 5).
- *Assign the obligations under the original contracts for differences between generators and the single buyer to distribution companies and large consumers.* This assignment should be done fairly, based on the demand profile of the distribution company. Provisions will have to be built into the original contracts for differences to make this assignment possible.
- *Develop regulatory capacity to supervise market participants in accordance with market rules.* The regulator will approve changes to the market rules and help resolve disputes between wholesalers.
- *Establish legislation to enable secondary trading of contracts for differences in electricity markets that is consistent with regulations governing the financial futures market.*

- *Establish retail and network licenses.* These licenses would carry specific conditions to guide the performance of the distributor when selling to consumers. The licenses would be enforceable under the Electricity Law.

To prepare for stage 3, retail competition, the work of separating retail and network functions should be initiated. This separation will be facilitated by the management information systems implemented during stage 1.

Stage 3: retail competition

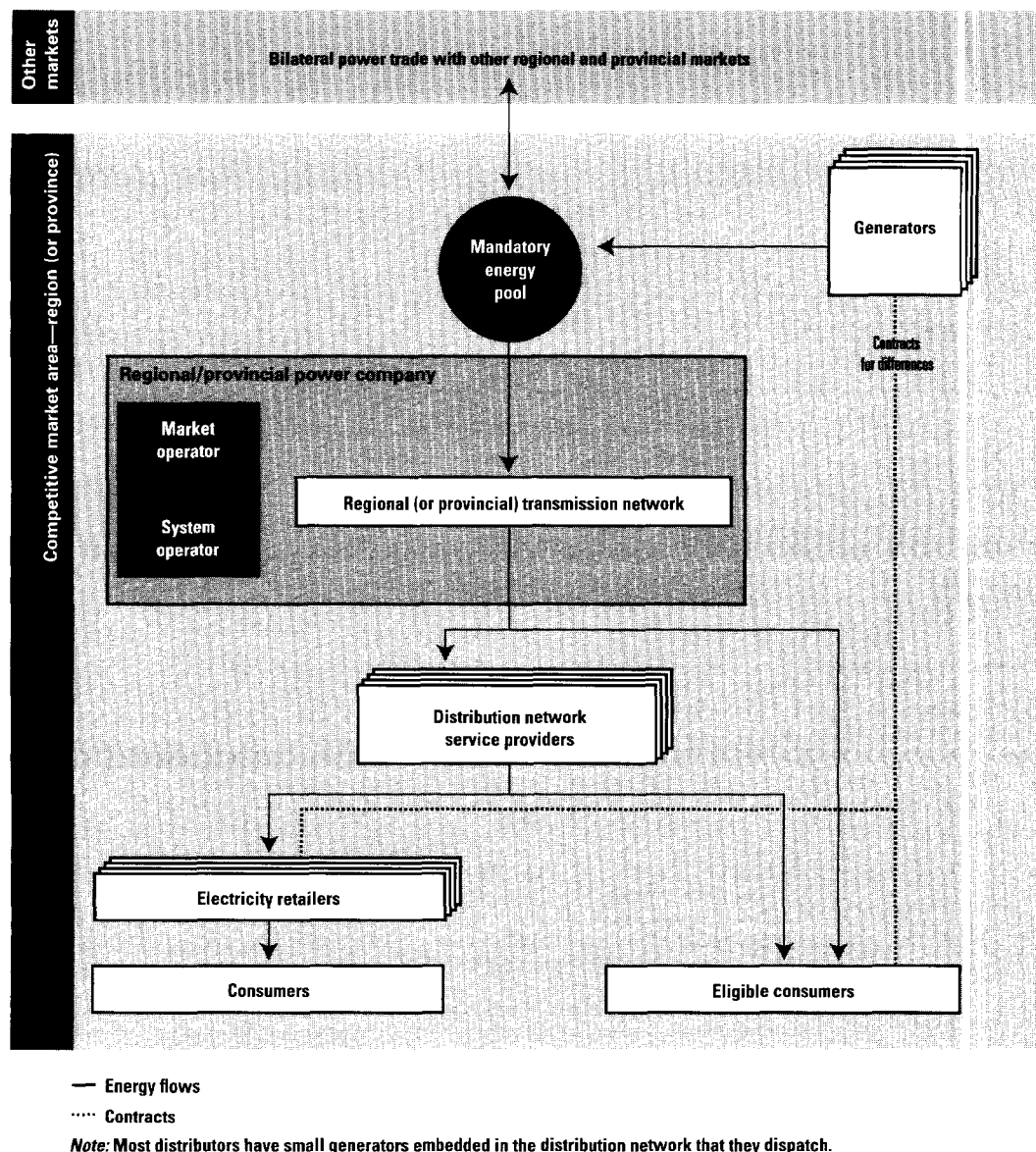
During stage 3 a retail market will be established (figure 2.4). This stage requires the functional and corporate separation of retail supply from operation of the distribution network. Most end users will purchase power through retailers. Some large industrial users will continue to buy directly on the wholesale market. The retail market will allow most users to choose the retailer from which they purchase energy. Retailers will also be encouraged to offer demand management products that provide incentives for consumers to use energy efficiently.

This stage will involve major upgrading of information systems, including metering technology, customer registration and transfer systems, customer information databases, and computerized billing systems. The regulator (or government) needs to develop retail competition policies for customer protection, retailer marketing behavior, dispute resolution, and orderly recovery of establishment costs. Retailers need to develop strong commercial skills as they assume the full market risk involved in a competitive market.

The following steps must be taken as part of the transition to stage 3:

- *Each distribution company must be restructured into a separate network operator and retailer.* Each distribution network operator will continue to manage the territory previously assigned to the distribution company. Retailers will be allowed to operate across territories. Distribution network operators will be regulated, and retailers will be allowed to compete for end users based on price and services. More independent retailers could be expected to enter the market at this stage.
- *Distribution network access tariffs must be developed and implemented.*

Figure 2.4
Stage 3: Retail competition



- The regulator must define a schedule of release that shows how franchised consumers will be phased into the retail market. Typically, the largest consumers are allowed to choose their retailer first, followed by consumers with lower consumption. In addition to achieving a smooth transition to full retail competition, this approach gives small consumers (such as households) time to learn about and evaluate their retail supply choices. Small consumers are least capable of initially negotiating rates with suppliers and require regulatory support and protection from unfair retail practices.
- Consumer meters should be installed that allow interval-specific consumption to be recorded. Installation of these meters should be coordinated with the phased schedule for consumer release into the retail market.
- The transition to retail competition requires changes in regulations and the licensing of network operators and electricity retailers. License requirements and regulatory supervision should set appropriate

guidelines for service levels, financial viability, and accountability; require periodic review and adjustment of tariffs for end users to protect small customers; and ensure that the network operator's license has provisions for a "retailer of last resort" if retailers are unable to meet their obligations.

Ensuring Adequate Generation Capacity

When adopting competitive power markets, it is extremely important to define a capacity pricing mechanism that ensures adequate investment in generation capacity without stimulating excess capacity. Experiences in Australia, Latin America, New Zealand, the United Kingdom, and the United States show that investors will add new capacity without long-term (life-of-plant) contracts if there is a reliable spot market and they have access to wholesale consumers. But if spot market prices do not reflect the balance between generation capacity and demand, there can be too much, too little, or inefficient investment in capacity.

Several options can be considered to address this issue, three of which are outlined below.¹ A feasible option for competitive power markets in China is an hourly capacity-related charge based on the operating reserve in the system, added to the market clearing energy price. This charge would be higher when there are lower reserves in the system and lower when reserves are higher.

- *An annual capacity payment.* An annual capacity payment (in yuan per megawatt per year) could be made for all capacity that meets some criteria of availability, and recovered from consumers through the bulk supply tariff. Where this has been done—for example, initially in Argentina—it has usually resulted in too much capacity because system operators and regulators have set the capacity price too high to ensure capacity, and the market responded by supplying more capacity more cheaply than expected. Such a system also requires the system operator to decide what kind of capacity qualifies for how much capacity payment—a particularly difficult problem when thermal and hydro capacity must be compared—and does not guarantee

that the capacity will be available when it is needed (as happened in Chile).

- *Installed capacity requirement.* A more market-based way to ensure adequate capacity is to require all wholesale buyers to contract for enough installed capacity to cover their expected consumption plus a reserve margin. Installed capacity requirements are common in U.S. markets, which have developed from vertically integrated monopolies. An installed capacity requirement, however, requires the system operator to make many detailed judgments—such as on projected peak demands, availability and maintenance of thermal generating units, water availability for hydro units, and so on—that directly affect the profitability of individual wholesalers and generating units. This level of system operator discretion is inconsistent with a competitive market. Shortening the period for which a capacity payment is made or an installed capacity requirement is determined and enforced (say, from a year to a month) eases but does not eliminate the problem of system operator discretion and discrimination.
- *An hourly capacity-related charge.* International trends in capacity pricing are moving toward hourly price supplements to the spot energy price determined in the pool. Conceptually, if generators are paid an unconstrained market clearing price for the energy they produce, hourly energy prices will result in payments to capacity, as well as ensure that installed capacity is available when it is needed—when hourly prices are high. The problem with this approach is that most energy pricing rules do not adequately reflect the value of energy during critical periods, such as immediately after the failure of a generating unit or transmission line. This is largely because the system operator acts outside the energy market to pay some generators for providing operating reserves and load following services. These actions tend to depress energy prices when operating reserves are actually used, which is precisely when energy is most valuable. As a result reserve generators do not get the revenues that would in theory compensate their investment costs. An energy pricing rule that does not include the costs associated with using operating reserves

Box 2.3

A method for determining a short-term capacity-related charge

Detailed analysis is needed to define the hourly capacity-related charge to be added to an energy pool price. The goal is to increase the energy pool price when the unused operating reserve is less than the target defined by system security standards. The following pricing method is recommended:

- Market rules must specify a maximum market clearing price, P_{max} , that corresponds to the estimated value of lost load. The maximum market clearing price will determine the energy price if it is necessary to shed load because of inadequate generation capacity. (Some U.S. systems use \$999 a megawatt-hour; in Bolivia the limit is \$500 a megawatt-hour.)
- System security standards define a target level of operating reserves, R_{Target} (in megawatts), for each hour.
- The energy pricing formula in the market rules (see box 2.2) will determine a market clearing price, P_p , based on generator bids (and dispatchable loads) during that hour.
- In any hour when the actual level of operating reserves, R_{Actual} , is less than R_{Target} , the energy price will be set equal to (for example):

$$(X^N \times P_p) + (1 - X^N)P_{max}$$

where $X = (R_{Actual}/R_{Target})$ and N (greater than or equal to 1) is a parameter to be determined.

With this formula, when $R_{Actual} = R_{Target}$ ($X = 1$), the hourly price is the standard price resulting from generator bids. When $R_{Actual} = 0$ ($X = 0$), the hourly price is P_{max} . When R_{Actual} is some fraction of R_{Target} , the price increases above P_p toward P_{max} quite rapidly, depending on the value of N . For example, with $N = 2$ the price will increase one-quarter of the way to P_{max} when R_{Actual} is one-half of R_{Target} .

The parameters P_{max} and N and the appropriate form of the function have to be chosen based on system modeling. A system model can be used to ensure that the capacity-related charge generates enough revenue to justify an investment in peaking capacity (such as a diesel-fired gas turbine) when the system reserve margin is at an reasonable level (perhaps 15–20 percent). When the reserve margin is greater than this amount, energy prices fall, particularly during peak periods. When the reserve margin is less than this amount, energy prices rise, particularly during peak periods. The result will be strong price incentives to maintain system reserve margins near the specified target.

will understate the true incremental cost of meeting demand when reserves are used.

These considerations suggest a way to improve simple energy pricing rules that ignore the difficult to quantify costs associated with drawing down operating reserves. If operating reserves are at or above a nominal target level (say, 15–20 percent), the energy prices implied by pool-determined spot energy prices will be about right. As operating reserves fall below the target level, the system operator takes increasingly costly measures—such as reducing voltage and overloading transmission facilities—the costs of which are not reflected in the energy price. Thus a supplementary hourly charge related to reserve levels can be added to the energy pool price (box 2.3). When operating reserves are reduced to the level at which load is almost lost, the energy price should equal the deemed value of lost load. The amount by which the cost of meeting incremental load exceeds the simple pool-determined energy price depends on the level of operating reserves, and some estimate of this additional cost should be added to the energy pool price.

The pool in England and Wales has such a charge, although it is determined a day in advance. But there are plans to modify this to reflect hourly capacity values. Argentina and Brazil use an explicit hourly capacity charge added to the hourly energy price as the operating reserve falls. A similar pricing mechanism is being implemented in Ontario, Canada.

Note

1. This section is derived from the March 2000 final consulting report for the Thailand Power Pool and Electricity Supply Industry Reform Study, Phase 1, prepared for the National Energy Policy Office (NEPO) by Arthur Andersen; National Economic Research Associates (NERA); Barker, Dunn and Rossi (BDR); Cameron McKenna; and Presko Shandwick. Report is available on <http://www.nepo.go.th>.

Chapter 3

Developing Bilateral Trade between Competitive Pool Markets

In the early years of competitive market implementation in China, technical and organizational factors will limit most competitive pool markets to areas made up of several provinces. Active power trading between these competitive market areas will deliver large economic benefits by improving the efficiency of resource allocation at the national level. In addition, active power trading can help integrate separate competitive pools.

Limited power trade occurs between regional and provincial networks in China. An efficient bilateral trading scheme, based on market principles, is recommended to increase trade between competitive pool markets. Bilateral power trading allows participants to directly negotiate power exchange quantities, duration, and prices—significantly reducing their investment and operating costs. There are three main sources of savings. First, from developing the cheapest generation resources on a regional or national basis rather than on a provincial basis. Second, from increased economies of scale by constructing larger facilities to serve wider areas. Third, from sharing operating reserves to ensure service reliability, reducing the need for each region or province to independently build reserve capacity.

This chapter recommends a strategy for developing bilateral power trade between competitive pool markets. This strategy could be implemented in parallel with the introduction of competitive pools. The proposed scheme will

support both long-term contract trading and spot energy transactions between the purchasing agents in adjoining competitive market areas. The trading scheme will have to be implemented and managed by an institution covering several competitive market areas. As competitive pool markets move to wholesale competition, distributors, traders and eligible consumers will be allowed to purchase directly from generators in other pools—progressively merging the initially separate competitive pool markets into a wider pool.

Establishing a Basis for Bilateral Trade

Two steps should be taken to initiate the development of bilateral trading between competitive markets. First, an institution should be established to develop and implement the trading scheme, and to coordinate bilateral transactions between several competitive market areas. This could be an existing institution at the regional or national level, or a new institution could be created. Second, government agencies should stop setting mandatory quotas for interprovincial and inter-regional power transfers.

The coordinating institution

The designated institution would be responsible for coordinating trade between the participants in the bilateral trading scheme. The main functions of this institution would be to:

- Collect and share information on the prices at which participants are willing to exchange power.
- Facilitate technically feasible power exchanges, ensuring stability of the power system.
- Settle accounts and financial transfers between participants based on actual trading.
- Coordinate transmission expansion plans and investments between competitive power market areas.

This institution will likely be affiliated with the recommended National Transmission Corporation (see chapter 4), because expanding transmission interconnections between competitive pool markets will be an important function. As the interconnections between competitive pool markets areas are expanded, integration of these markets will become feasible. To achieve the necessary independence from market participants and impartially facilitate the bilateral transactions, this institution must have no ownership linkage to market participants.

But while this institution should take the lead in developing and implementing trading rules and protocols, it should involve market participants in the process. The increase in bilateral trade will depend on the extent to which participants are convinced that the trading scheme serves their best interests.

Power quotas—a barrier to trade

Government agencies should stop setting mandatory quotas for interregional and interprovincial power transfers. These quotas typically require regional and provincial power companies and certain generators to provide defined amounts of energy to other regions or provinces at specified prices. These mandated transfers distort prices for bulk power and dilute incentives for trade. Some regions have already taken steps to phase out such transfers. In the East China power network, for example, administrative quotas are being replaced with bilaterally negotiated transactions. A government directive should be considered to gradually eliminate these quotas in all regions where they exist. As bilateral trading increases, it may also be possible to consider making these quotas tradable in a secondary market.

Designing the Bilateral Power Trading Scheme

Bilateral power trading will initially be between single buyers in adjoining regional and provincial competitive power markets. Some of these competitive market areas may already be operating with a mandatory energy pool market, while others may be in the early stages of the transition to the competitive pool and have changed very little. The bilateral power trading scheme should accommodate such differences in pace and stage of market reform between competitive market areas. To ensure that flexibility, the trading scheme should be voluntary, allowing participants to choose the type and timing of transactions. Participants in the bilateral trading scheme should be given price and quantity information on power import and export opportunities, as well as clear financial incentives to trade. But they should not be forced to trade.

A voluntary trading scheme is recommended for three reasons:

- It can accommodate trading between competitive markets at different stages of development—those with fully functioning mandatory pools, those that have made the transition to wholesale competition, and those that have yet to implement competitive pools.
- It allows time for market participants to see evidence of mutual financial benefits from trading and gradually increase their trading volumes. International experience indicates that this takes time to achieve.
- It is a practical way to introduce competitive market principles for trade between market areas that cannot be immediately integrated into a single competitive pool market. Once active trading begins, the need for transmission expansion becomes more apparent, leading to network development that facilitates market integration.

In general, there will be three types of transactions: long-term capacity or energy (for one or more years), short-term seasonal capacity or energy (for one day to many months), and hourly (or shorter) spot energy. The trading scheme should allow participants to freely negotiate contracts for the sale and purchase of long-term and short-term capacity and energy. This may be

referred to as the bilateral contract market. For spot energy transactions (hour-ahead trades), the institution that develops and facilitates power trading should operate a price-based energy broker mechanism.

Participants in regional and provincial competitive pool markets will determine the quantities of energy to be traded on a long-term, short-term, or spot basis depending on their assessments of future demand and expected price movements, and on their willingness or ability to bear price risk. International experience indicates that spot market trades will likely represent a small portion of the power traded between participants. Most energy will be purchased and sold on a long-term or short-term basis (figure 3.1).

The bilateral contract market

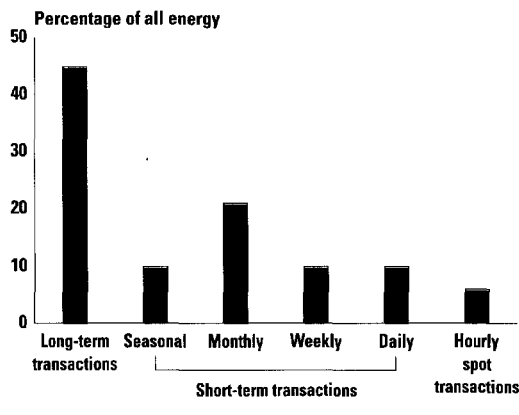
In the bilateral contract market the two parties directly negotiate power exchange quantities, durations, prices, and degrees of firmness. (Firmness refers to the priority that the two parties give to a transaction, and is normally related to the cost they would have to bear if the exchange does not occur.) Long-term and short-term contract trades enable participants to agree on commercial conditions among themselves, giving them the desired commercial and operational flexibility. Such bilateral transactions are already occurring in the East China power network, the North China power network, and between networks in southern China.

To facilitate the bilateral contract market, the system operator (in the designated market development institution) should establish an electronic forum—such as a bulletin board—on which market participants that wish to buy and sell capacity or energy can post their requirements and products. Such a forum would enable the efficient exchange of information between participants.

Although it is not vital for the system operator to participate in these bilateral transactions, the system operator needs to ensure that transactions can occur without jeopardizing the security and reliability of the system. The system operator's role should be limited, however, to avoid unwarranted interference. In general, the system operator does not need to be concerned with contract prices, but only with quantities and schedules to ensure that they are possible on the transmission system.

Figure 3.1

Indicative distribution of long-term, short-term, and spot energy transactions



A set of rules should clarify and limit the responsibilities of the system operator.

At times, transmission congestion and the sudden loss of generation or transmission lines may require the reduction or cessation of bilaterally contracted energy exchanges. In these instances the system operator must rank energy transactions in order of importance and direct each market participant to reduce or cancel its transaction volume as needed. In general, non-firm transactions would be reduced before firm transactions, and shorter-term transactions within each class of transaction would be curtailed before longer-term transactions.

Price-based energy broker for spot energy transactions

Several spot market options were evaluated before a price-based energy broker mechanism was chosen as being the best suited for the first stage of developing market-based trades between separate competitive market areas. A cost-based market was considered unsuitable for spot trading between competitive market areas for two main reasons. First, competitive pool markets in China are geared toward price-based competition rather than cost-based optimization. Hence it would be inconsistent to develop a cost-based market for trade between competitive pools. Second, a cost-based market would require detailed accounting rules to calculate incremental and decremental costs, as well as regular auditing. Monitoring and auditing can be very data intensive and difficult

to implement, and would likely infringe on areas best left to market mechanisms.

Given these constraints, it is recommended that spot transactions be encouraged on the basis of prices (independent of actual costs) set by market participants. An energy brokerage system will need to be established to facilitate the trading. The designated market development institution will operate as an intermediary, matching quotations from potential sellers with potential buyers every hour. In essence the energy broker will manage spot purchases and sales that take place after long-term and short-term contract transactions have been completed, with this spot energy being provided by units already on line on an "if, as, and when available" basis (box 3.1).

Advantages of the proposed bilateral contract and spot trading scheme

Using a price-based energy broker to manage spot transactions and leaving longer-term transactions to bilateral contracts offers several advantages:

- *Trading can occur between competitive market areas at different stages of development.* Even if only a few markets have adopted a competitive generation market and others have yet to make the transition, the proposed scheme will allow power trade between them.
- *It can be designed to encourage the expansion of the transmission interconnection between markets.* Such expansion is crucial for increasing the quantity of power traded. (It would be important for the transmission entity to obtain revenues from all power traded between

competitive market areas, not just spot transactions, to generate adequate revenues to expand the transmission system.)

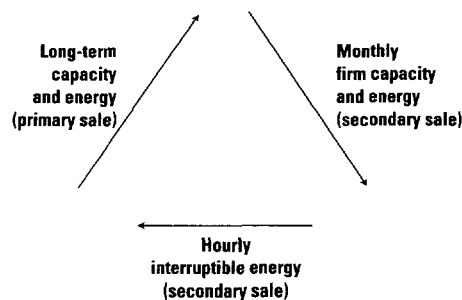
- *Price-based spot trading with an energy broker is a simple mechanism with easy to understand rules and good transparency.* This approach has been used in Norway and has been used extensively in the United States.
- *A full range of transaction choices and secondary market transactions are possible.* A secondary market allows participants to trade previously contracted energy purchase or sale obligations. Thus secondary markets are an efficient way for market participants to manage risk. Say a primary contract trade took place in which market A sold long-term capacity and energy to market B. In a given month, market B may find that it has excess capacity and energy that it wants to sell to market C. If market C, in turn, wants to sell energy during certain hours of the month, it could sell it to market A through the price-based energy broker (figure 3.2). This example illustrates the trading scheme's ability to accommodate secondary market transactions of all durations (long-term, short-term, and hourly spot).

Ensuring incentives for trade

In the early stages of reform, when regional and provincial competitive pool markets have not made the transition to wholesale competition and single buyers remain (that is, stage 1 of the transition to competitive markets), strong financial incentives and regulatory supervision will be required to encourage trade. Although the single buyers in competitive pools could be expected to engage in power import transactions that cut their purchase price, or power export transactions that increase their sales revenue, the incentive to trade will depend on the ultimate financial benefit. If a single buyer is not allowed to retain any benefit of the lower purchase price or higher sales revenue, and must pass it to consumers or generators, the incentives to seek trade opportunities will be weak. Thus it will be important to provide single buyers with financial incentives to trade power with other markets. This also suggests that at the provincial level it will be important to move quickly from the single buyer market to wholesale competition.

Figure 3.2

Secondary market for bilateral contracts



Creating the Power Trading Scheme

Bilateral power trading between competitive power markets should pave the way for the integration of these markets. Implementation of this scheme could occur in conjunction with the creation of competitive pools at the regional level. As noted, a key part of developing the bilateral trading scheme will be to establish an institution covering several competitive market areas. This institution will include the transmission function between these market areas, as well as the system and market operator functions. The institution will be responsible for:

- *Transmission functions*—maintaining and expanding the transmission network between competitive market areas. The cost of transmission will be recovered from transmission charges levied on market participants.
- *System operator functions*—operating the interconnected transmission network in accordance with market rules. Principal responsibilities will be to maintain system security and run emergency procedures when the system is at risk, balance supply and demand in coordination with regional and provincial system operators at the com-

petitive market level, manage constraints on the grid, obtain ancillary services for transmission, and coordinate maintenance programs for generation and transmission across competitive markets.

- *Market operator functions*—enforcing market rules and ensuring that bilateral trading rules promote competition, administering the bilateral contract market, operating the hourly spot market, establishing and monitoring metering and energy settlement systems, collecting transmission charges from market participants for use of the network, and dealing with disputes through the process laid down in the market rules.

This institution could be an affiliate of the proposed National Transmission Corporation. In the asset restructuring that may be required to establish such an institution, it would be important to avoid conflicts of interest in its operations. Thus the institution should not own or operate any generation assets. If this institution is formed from existing regional power groups, some of whom own generation, it would be essential to establish these generators as completely independent, separately owned firms.

Figures 3.3 and 3.4 show the structure of the power system before and after the establishment

Figure 3.3
Existing power exchange arrangement

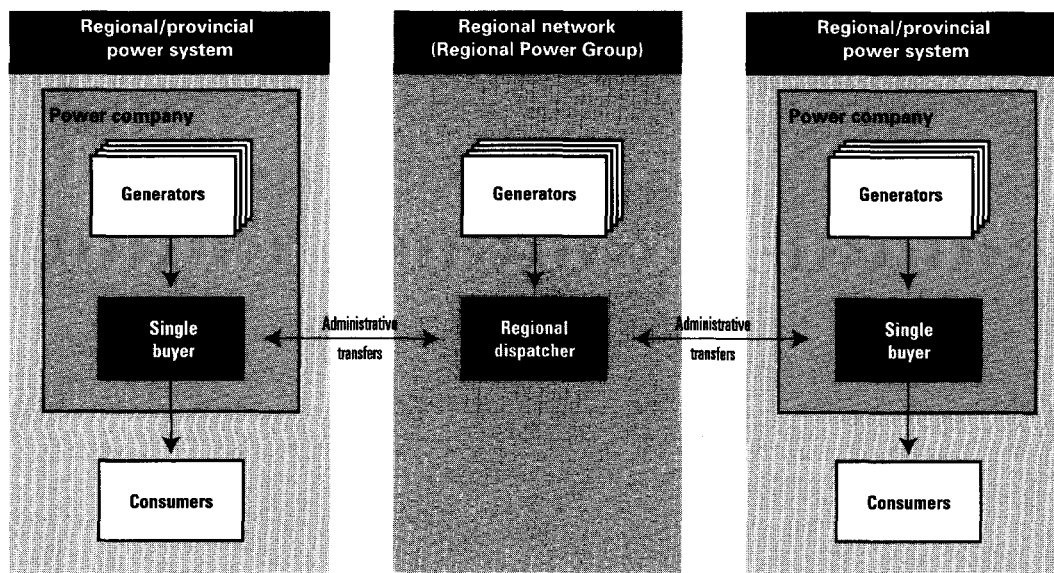
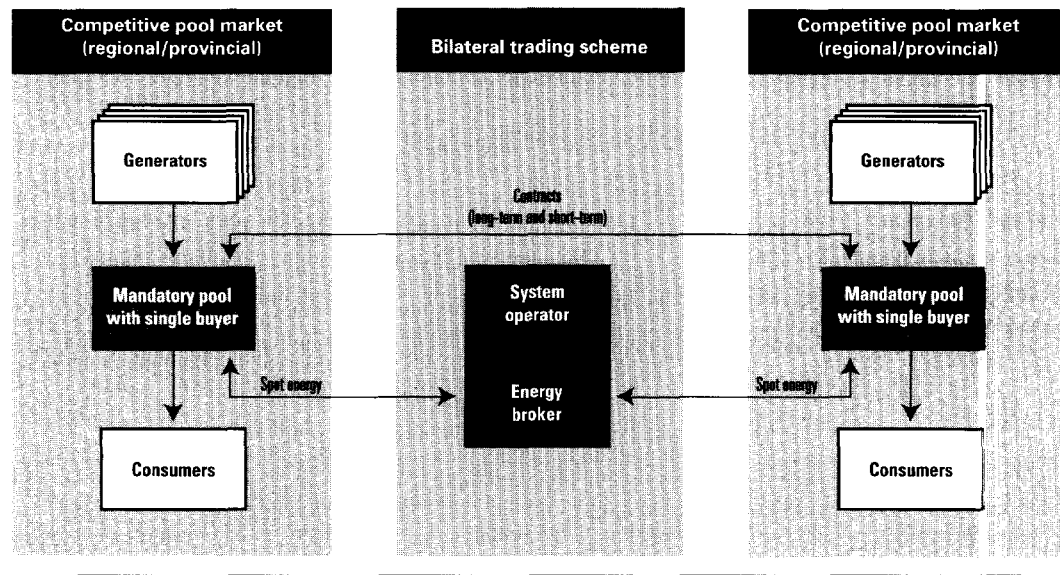


Figure 3.4

Bilateral power trading between competitive markets



of the bilateral trading scheme. Figure 3.3 shows existing power exchange arrangements between regional and provincial systems. Currently most trade is based on administrative transfers, with quantities and prices defined by a regional power

group or similar entity. Figure 3.4 shows the structure that would be in place when competitive pool markets are formed at the regional or provincial level and the proposed bilateral power trading scheme is implemented.

Box 3.1

Operating the price-based energy broker

Motivation for a spot energy transaction

The example below demonstrates the underlying motivations for conducting a spot energy transaction between two regional or provincial market areas. It emphasizes the importance of incremental cost—the price bid by the market participant to increase generation—rather than average cost in the decisionmaking process.

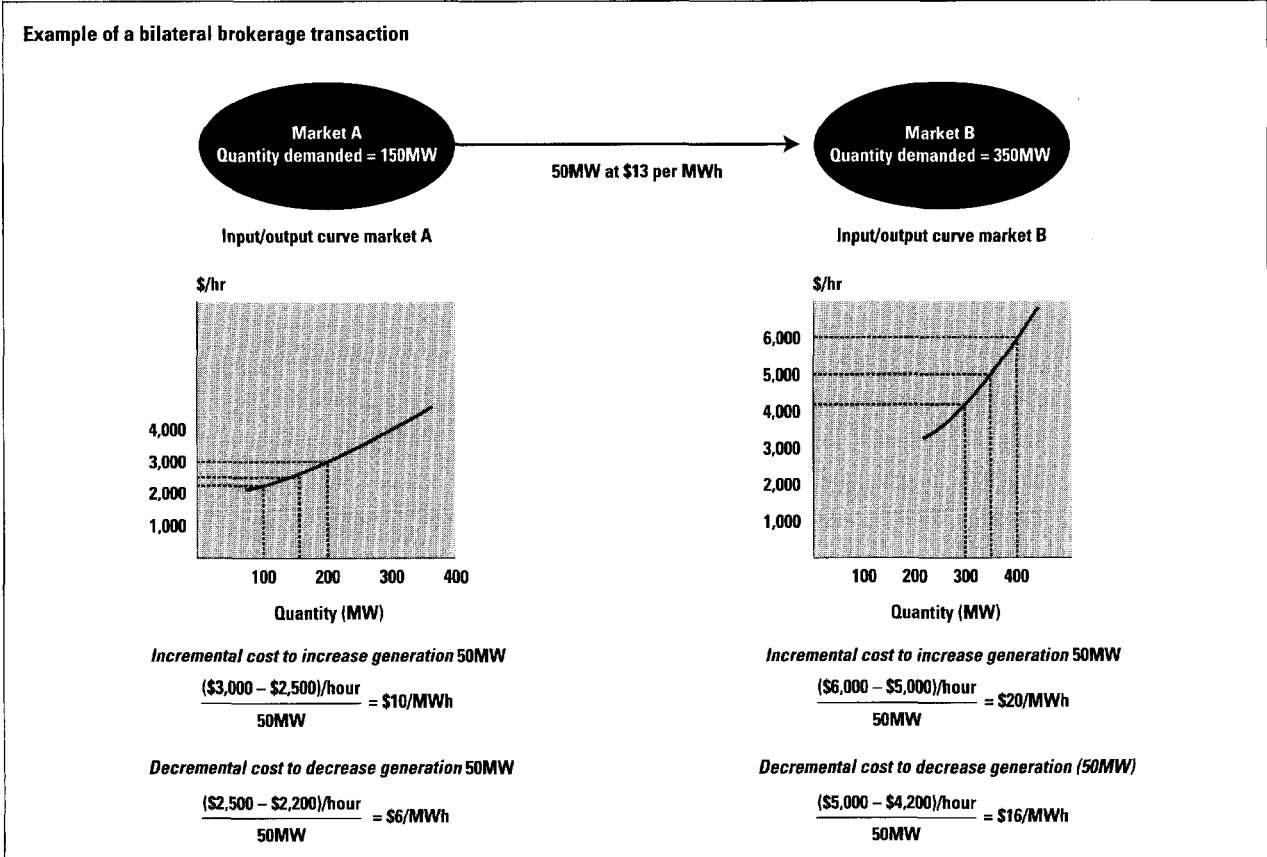
Suppose that market area A forecasts demand of 150 megawatts for the next hour and market area B forecasts demand of 350 megawatts. The average cost of production for market A is \$2,500 an hour divided by 150 megawatts, or \$16.67 a megawatt-hour. Market B's average cost of output is \$5,000 an hour divided by 350 megawatts, or \$14.28 a megawatt-hour.

The dispatcher in each market focuses on the incremental and decremental costs, however, not the average cost (see figure). By reducing its generation by 50

megawatts, market A reduces its costs by \$6 a megawatt-hour. Increasing its output by the same 50 megawatts raises market B's cost by \$20 a megawatt-hour. Because market B's incremental costs exceed market A's decremental costs, it would not make economic sense for market A to reduce its generation and purchase output from market B. Rather, it would make sense for market A to increase its generation and for market B to reduce its output. Market A's incremental cost of generation is \$10 a megawatt-hour, and market B's decremental cost is \$16 a megawatt-hour. Market B would thus save \$6 a megawatt-hour by cutting back its production and purchasing power from market A.

In this bilateral brokerage transaction, the seller and buyer of electricity split the difference in price, sharing the savings. Under the split savings method in this example, the

Box 3.1 continues on page 40



Box 3.1 Operating the price-based energy broker *continued*

price paid by the buyer is halfway between the incremental and decremental costs. Market B pays market A \$13 a megawatt-hour, providing market A with \$3 a megawatt-hour above its actual costs and saving market B \$3 a megawatt-hour.

Implementing spot energy transactions

The functions of the energy broker are described below. Rather than contact every market participant, the dispatcher in each market contacts the broker for a full listing of incremental and decremental quantities and quotations. This listing—or matching of quotations, in some systems—is prepared every hour for the successive hour. The illustrative example used below is based on the situation in east China, where provinces are still organized as separate markets.

- **Step 1: collecting price quotations.** The first step is to collect price quotations from each market participant (box table 1). The sell quotation represents the price a province charges for providing additional energy (and necessary operating reserves), plus a profit and any amount added to cover forecast error. The buy quotation represents the cost a province avoids incurring by reducing output, plus any savings and other adjustments. All quotations must be submitted to the broker at least one hour before the transaction occurs.
- **Step 2: ranking price quotations.** Once the broker has received all quotations, it ranks them. Sell quotes are ranked from low to high; buy quotes are ranked from high to low (box table 2). Suppose the quotations shown in box table 1 were submitted to the broker by market participants. The broker would rank the quotations as shown in box table 2.
- **Step 3: matching price quotations.** Once the buy and sell quotations have been collected and ranked, the broker matches the participant with the lowest sell quote with the participant with the highest buy quote. After this match is made, the next-highest buy quote is matched

with the next-lowest sell quote. The process continues until there are no more quotes to be matched or until the sell quotes are higher than the buy quotes, precluding further transactions. This procedure is known as the high-low method of matching.

In this example Jiangsu, which wants to sell 100 megawatt-hours at 20 yuan a megawatt-hour, would be matched with Zhejiang, which wants to buy 50 megawatt-hours at a maximum price of 70 yuan a megawatt-hour (box table 3). Since Zhejiang buys only 50 megawatt-hours, the transaction leaves Jiangsu with 50 megawatt-hours to sell. It then moves to the second-highest buy price, that quoted by Shanghai. Once Jiangsu has sold all of its power, Anhui becomes the least-cost seller. Since Shanghai needs another 50 megawatt-hours and its buy quote exceeds Anhui's sell quote, Shanghai purchases 50 megawatt-hours from Anhui. After this transaction, no matching will take place, because the next-lowest buy quote, from Jiangsu, is lower than the sell quote for Anhui's remaining 30 megawatt-hours.

Not all transactions that appear economic based on high-low matching or that may be desirable for individual provincial dispatchers will be technically feasible. Lack of transmission interconnections, congestion constraints, and stability limitations specified by system operators will prevent some spot market transactions. Where transactions cannot be made, the broker will match the highest remaining buy quote with the highest remaining sell quote.

- **Step 4: determining the transaction price.** In the example above, the transaction price for each match is halfway between the total buy and sell quotations. Zhejiang's sell price is 70 yuan a megawatt-hour; Jiangsu's buy price is 20 yuan a megawatt-hour. Dividing 70 plus 20 by 2 yields the split savings transaction price of 45 yuan a megawatt-hour. The total value of the transaction is 50 megawatt-hour times 45 yuan per megawatt-hour, or 2,250 yuan. The gross savings per hour is 50 megawatt-hours times the difference between the buy quote and
-

Box table 1

Sample sell and buy quotations received by an interprovincial energy broker

Province	Sell quotations		Buy quotations	
	Volume of power (megawatt-hours)	Price (yuan per megawatt-hour)	Volume of power (megawatt-hours)	Price (yuan per megawatt-hour)
Jiangsu	100	20	50	15
Anhui	80	26	100	14
Zhejiang	10	75	50	70
Shanghai	50	50	100	40

Box table 2

Ranking of sell and buy quotations by an interprovincial energy broker

Province	Sell quotations		Province	Buy quotations	
	Volume of power (megawatt-hours)	Price (yuan per megawatt-hour)		Volume of power (megawatt-hours)	Price (yuan per megawatt-hour)
Jiangsu	100	20	Zhejiang	50	70
Anhui	80	26	Shanghai	100	40
Shanghai	50	50	Jiangsu	50	15
Zhejiang	10	75	Anhui	100	14

Box table 3

Matches between sellers and buyers of power

Seller	Buyer	Volume of power (megawatt-hours)	Sell quote (yuan per megawatt-hour)	Buy quote (yuan per megawatt-hour)
Jiangsu	Zhejiang	50	20	70
Jiangsu	Shanghai	50	20	40
Anhui	Shanghai	50	26	40

the sell quote, or 2,500 yuan. To provide adequate revenues to cover transmission costs and provide incentives for future investment, the split savings method could be modified so that an equal amount is deducted from spot market buyers and sellers and given to the interprovincial transmission grid owner. (Revenues from spot trades will not, however, be adequate to finance transmission expansion. A comprehensive transmission pricing system is required; see chapter 4.)

- **Step 5: informing the parties to the transaction.** Having identified a potential transaction and determined the price at which the transaction can occur, the energy broker returns this information to the relevant provinces at some agreed period before the transaction is expected to occur (say, 30 minutes before the hour).
- **Step 6: implementing the transaction.** Each province confirms its participation in the transaction and carries out the exchange. This confirmation should take place at least 10 minutes before the transaction occurs.

Source: Adapted from James V. Barker, Jr., "Electric Energy Brokering: An Explanation and Status Report," *Public Utilities Fortnightly*, 4 February 1992; and from Barker, Dunn, and Rossi, Inc., draft *Market Operation Manual*, developed for the East China Electric Power Group Corporation, 1999.

Chapter 4

Addressing Transmission Issues

A high-voltage transmission network is crucial for the development of competitive power markets in China. Without an adequate transmission network, trade in power will be constrained, and it will not be possible to create efficient markets. Moreover, the way transmission is organized and regulated can create the right incentives for developing economic sources of power that are located at great distances from load centers.

Transmission has not been recognized as a separate and important component of the power supply chain in China. Regional and provincial power companies have been organized around core generation plants and power supply bureaus, and transmission has not been considered a distinct service. Although this situation is changing, the physical and operational distinction between the power supply bureau's distribution network and the transmission network remains unclear. The low priority given to transmission is also evident in the lack of government guidelines for recovering transmission investment costs through power tariffs. As the power sector moves toward increased competition, transmission will have to be given increased priority and recognition.

To create a competitive power market, five transmission issues must be addressed. First, all market participants must be given open and nondiscriminatory access to the transmission network—access that can be assured only by an independent transmission system operator. Second, an efficient organizational model for transmission ownership and operation must be

implemented. Third, planning and implementation of transmission expansion must ensure that the grid is expanded in a timely fashion. Fourth, transmission services must be efficiently priced to ensure that they cover costs and provide incentives to expand the network. Finally, transmission regulation must ensure nationwide consistency in transmission rules and the reliability of the network. This chapter reviews each of these issues.

The Open Access Principle and Independence of the Transmission System Operator

If power markets are to be competitive, all market participants must have open and nondiscriminatory access to the transmission network by paying a nondiscriminatory tariff. Nondiscriminatory access to transmission requires that the transmission system operator be independent of all market participants. This principle has been widely recognized in countries that have implemented competitive power markets.

Independence may seem like an abstract concept, but it has important real-world consequences. Market participants will be reluctant to invest unless they believe that they will have equal access to the grid. When one or more generating companies in a competitive market area have some form of ownership interest in the transmission entity, there are numerous and subtle ways for generators to get favored access. For

example, the transmission-affiliated generators could pay lower connection fees than those charged to their competitors. Or, if there are constraints on the grid that require occasional curtailments, these generators could be the last generators to be curtailed.

When a single market participant or class of market participants has control over decisions made by the transmission system operator, the opportunities for discrimination are almost endless. Thus it is important to eliminate vertical ownership linkages between the transmission system operator and market participants. Europe has had major difficulties in moving to a single competitive electricity market because of continuing vertical linkages between generators and transmission operators.¹

The U.S. Federal Energy Regulatory Commission, the national body regulating electricity, recently stated that “the principle of independence is the bedrock” on which a regional transmission organization must be built and that any regional transmission organization must be independent in “both appearance and reality” (FERC Order 2000, 15 December 1999; available at <http://www.ferc.fed.us>). The British government reached a similar conclusion when it restructured its power sector in 1990. As a precondition for restructuring, the British government mandated that no market participant could own more than 1 percent of voting interests in the National Grid Company and that no person affiliated with a market participant could serve on the company’s governing board. The 1994 Bolivian Electricity Law mandates that no generation or distribution company can own capital stock in, or exercise administrative control over, any transmission company.

In some countries it has been argued that cross-ownership of the transmission system operator by generators or distributors should be allowed because the regulator can act as a “police officer” who will detect and punish any discriminatory behavior. But for several reasons, relying on the regulator to police conduct may not be effective. First, discrimination is often subtle rather than overt. A transmission system operator owned by one or more market participants can often justify its actions with plausible operating or reliability arguments—even though its true

(but hidden) motivation is to favor the commercial interests of its owners or affiliates.

Second, even if the discriminatory actions are obvious, there is an inevitable lag before they can be discovered and remedied. During the lag period, competitors may suffer significant commercial losses that could put them out of business. Third, even if the regulator discovers and prohibits the discriminatory behavior, it is often possible for a nonindependent transmission system operator to develop slightly different variants of the prohibited actions that were not contemplated by the regulator. This puts the regulator in the difficult position of having to identify and respond to discriminatory behavior after it has occurred.

To achieve nondiscriminatory open access to the transmission grid, it is essential that explicit ownership restrictions be imposed. These restrictions must work in both directions: the transmission company and its employees should not be permitted to have ownership interests in market participants, and market participants should not be permitted to have ownership interests in the transmission company. In some countries market participants argue that they should be allowed to have passive interests in the transmission entity, either permanently or for a transition period. Passive ownership is sometimes described as “ownership without control.” In theory, a passive owner is unable to influence the company’s operating and investment decisions. The problem with this arrangement is that it forces the regulator to determine whether ownership is truly passive. Doing so is not easy because it requires regulators to examine internal corporate rules and procedures to determine the rights and privileges that the passive owners may have reserved for themselves. A better approach is to totally prohibit cross-ownership between the transmission entity and any market participant.

In China the State Power Corporation of China (SPCC), through its subordinate provincial and regional entities, owns nearly all transmission, a large share of generation capacity, and many distributors. These ownership links with generators and distributors should be dissolved. As a practical matter it may be worth focusing first on separating generation from the transmission grid—a move that has been affirmed by the

State Council (State Council Directive 148, 1999). Generation should be separated into companies—both state-owned and privately owned—that are not linked to the SPCC. During the next phase distribution could be separated from transmission.

Structure and Ownership of Transmission Facilities

China's vast power system and the reform objective to create competitive pool markets that are as big as technically and economically feasible, with the right incentives for future integration, are important factors that influence the choice of organizational model for the transmission system. Given the State Council's decision to completely separate generation from the transmission grid, the relevant questions are: Should the transmission organization be provincial, regional, or national? If a National Transmission Corporation is desirable, should the relationship to the next level be as subsidiaries or as branches? And how should transmission-related functions, such as system operator and market operator, be organized?

Two basic structural options are worth considering for transmission organization in China. The first is creating a National Transmission Corporation with regional branches or corporate subsidiaries. The second is having Regional Transmission Companies with provincial branches or subsidiaries. The two options are compared in table 4.1. Conceptually, other approaches could be considered. But in the medium term, legal, policy, and implementation constraints preclude options based on private sector involvement in transmission and further decentralization of responsibilities for transmission expansion.

For several reasons, a National Transmission Corporation with regional branches would be the better approach for China:

- A National Transmission Corporation would ensure that crucial interregional transmission connections are developed. A National Transmission Corporation would base its transmission expansion decisions on China's best interests. For various reasons, regions may oppose transmission interconnections with other regions—constraining trade.

- A National Transmission Corporation would ease structural changes such as increasing the size of the market by merging competitive pool markets as the grid is developed. Such a corporation would eliminate corporate or institutional resistance and constraints to expanding market size.

- A National Transmission Corporation could play a major role in brokering bilateral power trade between competitive pool markets at the regional or provincial levels. The need for an entity to undertake the functions needed to support bilateral power trade is discussed in chapter 3.

- The structure requires the least change from the present. Since the State Power Company of China owns all transmission assets, even those at the regional and provincial levels, creating a National Transmission Corporation with regional branches should be easy. Indeed, it may be counterproductive to expend limited resources to drastically reorganize the transmission system into regional or provincial companies too early in the reform process—given that the higher-priority separation of generation from transmission will require considerable resources.

Choosing between lower-level branches or subsidiaries

It is recommended that the National Transmission Corporation be organized with branches or divisions in each competitive market area, rather than as separate subsidiaries that own their assets. A subsidiary is a separate legal corporate entity with its own board of directors and balance sheet, and in effect owns the assets under its control. A branch does not. A subsidiary is appropriate only when there is a question of subsequent asset divestiture, since a separate corporate entity is a precondition for divestiture.

A subsidiary has more managerial and decisionmaking autonomy than a branch. Thus subsidiaries could be harder for the National Transmission Corporation to control because of the potential friction between corporate layers. The main reason for a National Transmission Corporation with branches is that a subsidiary company, such as a provincial or regional transmission corporation, would be weakened by the

Table 4.1

Two organizational models for transmission in China

	National Transmission Corporation with regional branches or subsidiaries	Regional Transmission Companies with provincial branches or subsidiaries
Advantages	<p>Makes it easier to adopt and implement common market rules and transmission pricing mechanisms nationwide, allowing effective market integration and increased trade</p> <p>Facilitates expansion of the interregional system and development of trade between competitive regional markets</p> <p>Would allow the State Power Corporation of China to be developed into a National Transmission Corporation after the separation of generation. Also would allow strong project team capabilities to develop</p> <p>A fully integrated management structure is a good first step in reforming the transmission function. It provides the flexibility for creating a more decentralized regional management structure with strong skills</p>	<p>It would be easier to identify accurate transmission costs for each regional and provincial company—making it easier to ensure that transmission companies are accountable for meeting performance standards</p> <p>Would create competitive tensions between Regional Transmission Companies because of their desire to demonstrate technical and commercial performance capability</p> <p>Regional companies may be quicker in identifying transmission expansion needs and making transmission expansion decisions within regions, leading to increased efficiency</p> <p>Regional companies organized around energy pools would be more likely to respond to market needs faster</p>
Disadvantages	<p>It might be difficult to identify accurate transmission costs for each provincial and regional market. A National Transmission Corporation could seek to cross-subsidize transmission prices within China—making it hard to correctly assess the economic and financial viability of individual lines</p> <p>It may take longer to identify and construct necessary transmission capacity due to the possible centralization of planning and approval authority</p> <p>A National Transmission Corporation that micromanages energy pools at the regional and provincial levels could seriously impede effective and efficient market operations</p>	<p>There would be no clear institutional mechanism or responsibility for the construction of interregional transmission lines to increase trade</p> <p>A new role would have to be found for the State Power Corporation of China</p> <p>Regional Transmission Companies might develop market rules that restrict trade and market integration</p>

expansion of trade and the consolidation of markets. Thus a subsidiary would be less likely to build the transmission that would enable trade to expand, unless there were clear incentives to do so.

Furthermore, as transmission expands, the optimal size of an organizational unit will increase. Subsidiaries are harder to reorganize than branches. Organizing the National Transmission Corporation with branches or divisions in each area would enable changes to be made as the grid is developed.

Still, there may be strong institutional reasons or constraints that lead to a preference for organizing lower-level entities as subsidiaries rather than as branches. If that is the case, the benefits sought from organizing as branches should be

encouraged through corporate governance mechanisms.

Organizing the system and market operator functions

Countries that have created or are contemplating competitive power sectors have generally used one of two approaches to organizing the system and market operator functions. In the first approach, referred to as the Transco model, the transmission owner also functions as the system operator. In the second approach, known as the ISO-Gridco model, the transmission owner and the system operator are separate, and an independent system operator provides all operating and dispatch instructions while one or more independent grid companies build, own, and

maintain the physical grid facilities. The two models are described in table 4.2.

Heated debates are occurring in several countries over the relative merits of the two approaches. Although international experience shows that adequate competition can be achieved through either approach, there is not enough experience to conclude that one is superior to the other. In recent years more countries appear to have chosen the ISO-Gridco model.

For China it is suggested that the Transco model be adopted for at least the early stages of reform. Specifically, it is recommended that the

system and market operator be combined with the branch of the National Transmission Corporation responsible for transmission within a given competitive market area. This approach is recommended for four main reasons:

- The investment needed to expand the high-voltage transmission grid throughout the country is more likely to occur if a single entity is charged with this responsibility in each competitive market area. While a separate system operator may be given clear legal responsibility to expand the grid, it may find it difficult to do so if it has to depend on

Table 4.2

The Transco and ISO-Gridco models of transmission ownership and operation

	Combined transmission owner and system operator (Transco model)	Independent system operator and separate transmission owner(s) (ISO-Gridco model)
Features	Entity is a publicly or privately owned, regulated, for-profit corporation that owns and operates all transmission facilities in its geographic area	Independent system operator is usually a nonprofit entity that operates but does not own the transmission facilities in its region. The operator has leasing or transmission control agreements with each of the entities that own the transmission facilities in its region Tariffs to recover the capital and operating costs of the transmission facilities are collected by the independent system operator and remitted to transmission owners. The operator may charge a separate grid management fee to cover its operating costs
Advantages	Better able to raise capital, implement projects, and make fast decisions on grid expansion Easier to implement where system operators and transmission owners have been integrated	More likely to make unbiased decisions about transmission expansion Better able to make unbiased assessments of power market operation
Disadvantages	Difficult to design incentives that lead to unbiased operational and investment decisions. For example, to maintain voltage at a particular location, the Transco may prefer to install new capacitors, even if it would be cheaper to purchase reactive power from a generator. The Transco may also favor increasing grid transport capacity to meet growing load at a particular location, even if new generation is a cheaper alternative	Difficult for the independent system operator to expand the grid because it must rely on other entities to finance and implement investments. (This problem has recently emerged in the United States.) Without a profit incentive, independent system operators may become bureaucratic and inefficient organizations Difficult to design an institutional framework in which the independent system operator has clear responsibility for expanding the grid and requires the transmission owner to do so May be difficult to design a workable governance scheme that ensures that independent system operators are truly independent of market participants
Examples	National Grid Company (United Kingdom), Statnett (Norway), Polish Power Grid Co. (Poland)	CAMMESA (Argentina), NEMMCO (Australia), IMO (Ontario, Canada), five independent U.S. system operators (California, New England, New York, Texas, Mid-Atlantic), REE (Spain). Proposed for Brazil, Mexico, and Peru

other entities to finance and perform the expansion.

- Because generation is to be completely separated from the grid, the potential for discriminatory dispatch that often leads to a preference for the ISO-Gridco model is not an issue. There may be a few problems during the transition to full ownership separation of generation. But these problems could be mitigated through mutual oversight by the generators themselves.
- Because there will be only a single owner of all transmission assets, at least initially, there is no particular reason to create a separate system operator. Countries that have multiple owners of transmission assets (Argentina, the United States) have had to create a separate system operator; this is not the case in China.
- The implementation issues that arise with the creation of a separate system operator may detract from other important implementation tasks.

After the first few years of operations under the Transco approach, an assessment should be made by the regulator, perhaps with the assistance of a panel of neutral experts. If it is concluded that the competitive market would benefit from increased transparency, the panel could make recommendations for an alternative structural option, such as the separation of the system operator. To facilitate regulation of transmission entities at the national and branch levels, these entities should be required to keep separate accounts for the system operator and transmission functions.

The main argument against combining all the functions would be the difficulty of regulating such a powerful company. Thus the regulator must be given strong powers to oversee the Transco model, and to use these powers to create incentives for efficient operation of the grid.

Planning and Implementing Transmission Expansion

In China there is a need to expand the high-voltage transmission grid throughout the country to facilitate economic power trades between competitive pool markets, as well as in response to the demand of market participants within competitive pools. Transmission expansion plan-

ning and implementation must be carefully integrated with the operations of the competitive pool markets and bilateral trading arrangements between them. The overall objective of grid expansion is to ensure that transmission entities have the right incentives to make grid investments that are economically justified and to reject those that are not. An economically justified expansion is one for which the additional benefits (usually measured as the reduction in wholesale power prices) are greater than or equal to the costs of expansion. While these principles are easy to state, actual implementation is often difficult because as the sector becomes more competitive, there will be more separate entities, often with conflicting commercial needs.

Goals of transmission expansion

In a competitive power market, transmission is expanded to:

- Interconnect generation or load (for example, by building a radial line from a new generator or load to the transmission system).
- Protect or enhance system reliability (for example, by replacing older, less reliable equipment with newer, more reliable equipment).
- Improve grid efficiency (for example, by replacing high-loss equipment with lower-loss equipment).
- Enhance operating flexibility to improve reliability (for example, by adding new switching capability).
- Reduce or eliminate congestion to facilitate competition (for example, by adding new transmission lines or increasing the capacity of existing lines).
- Reduce the local market power of a particular generator that may be the only feasible supply source in a particular region.

This list suggests that a transmission project may be driven by the need for both competition and reliability. In a competitive power market, the institutional environment and incentives for transmission planning and expansion must be able to accommodate both needs.

Centralized and market-driven approaches to planning and expansion

There are two approaches to planning and implementing transmission expansion—the top-down

(or centralized) approach and the bottom-up (or market-driven) approach. Top-down planning and expansion decisions are made by the system operator, which has detailed knowledge of system conditions and flows. The system operator also has the best information on likely future system conditions and flows, because it receives information on which generators and loads are likely to connect or disconnect. Because of its access to information and its familiarity with the day-to-day requirements of the system, the system operator will be able to make informed transmission expansion plans.

Bottom up planning and expansion occurs when one or more market participants or a private entrepreneur initiates and finances grid expansion. In effect, such transmission expansion is undertaken by coalitions of users or independent entrepreneurs rather than by the transmission company under market access rules. Any proposed expansion must still meet the technical standards established by the transmission company or independent system operator.

There are many potential problems with the bottom-up approach. The most significant is the difficulty of forming such coalitions, because almost every new transmission line is likely to produce winners and losers. In the case of a new transmission line that increases export capacity from a region, the winners will be the generators in the exporting region (whose prices will rise) and the distribution companies in the importing region (whose prices will fall). The losers will be the generators in the importing region (whose prices will fall) and the distribution companies in the exporting regions (whose prices will rise). These varying commercial outcomes may lead to disputes in allocating costs among members of the possible coalition, as well as strong opposition by market participants whose competitive position would be hurt by the elimination of the constraint.

The bottom-up approach is also associated with other potential problems. Construction of capacity may be delayed because a participant is reluctant to incur the high initial cost of building a line, which may benefit others who are unwilling to share in the initial costs. Scale economies may be lost if a new generator constructs a low-capacity radial line to the main grid when a

large-capacity line and towers may be justified from a total life-cycle cost perspective. Participants may also be unwilling to share in investments that improve the overall reliability of the grid.

In the initial stages of implementing competitive power markets in China, the top-down approach should be adopted. The bottom-up approach requires sophisticated mechanisms to allocate transmission rights to users and assign the costs of new facilities. These mechanisms would only complicate the already intricate market development process. In addition to avoiding the problems of bottom-up approach, the top-down approach is likely to lead to the required transmission expansion and provide the convenience and familiarity of the central-planning approach that has been used for years.

Although the top-down approach has similarities to the central planning approach, there are important differences. First, in addition to clearly defined planning rules to guide the transmission entity and system operator, there should be an explicit legal obligation to plan and ensure the timely construction of facilities needed to promote competition and maintain or improve reliability. These planning rules and legal obligations can be established by the regulator. The legal obligations of the transmission entity can be included in the license issued by the regulator. The legal obligation should be supported by incentives for appropriate investments.

In some countries legal obligations have not been complied with because they conflicted with commercial incentives. For example, despite its legal obligation to expand the grid efficiently, the U.K. National Grid Company, a privately owned transmission company, allowed the cost of congestion on the grid to increase from \$180 million in 1991 to \$590 million in 1994. The company had weak incentives to take action because it was allowed to pass the costs of congestion on to grid users. The problem was rectified by the regulator, which later linked the company's profits to congestion targets. Although the transmission system could be improved by providing explicit congestion price signals to grid users, the general lesson is that underlying economic incentives to expand the grid must be aligned with regulatory requirements to do so.

Second, the regulator should not manage this planning, because it generally will not have the information or experience required. But the regulator must review the expansion decisions of the system operator and the transmission entity to ensure that they are in the best interests of competition. Third, the regulator, acting on behalf of the state, may need to help the transmission company fairly and efficiently acquire publicly owned land or land from unwilling individuals or enterprises. Given the importance of the regulator's role in ensuring efficient grid expansion, it should make decisions quickly. Long delays can impede market development and lead to unnecessarily high bulk power prices.

The ultimate goal should be to develop a transmission planning and expansion process that accommodates both the top-down and bottom-up approaches. Because the bottom-up approach is relatively new, China should assess the experiences of other countries that are experimenting with it before adopting such an approach.²

Transmission Pricing

In competitive markets, transmission tariffs should achieve two goals. First, they must allocate the costs of transmission services among customers in a way that reflects their use of the transmission system and provides incentives for efficient use of the system. Second, they must provide commercial incentives to invest in transmission infrastructure.

In countries with mature power systems—such as the United Kingdom and the United States—transmission pricing has focused on the first objective. This approach was reasonable given that the value of existing assets in these countries far outweighed new investment costs. But China requires enormous transmission investments to connect new generation to the grid and transfer the power to load centers. Hence transmission pricing must ensure that there is adequate compensation for new investment. Because competition will increasingly be used to guide investment and operating decisions, transmission pricing will play a critical role in inducing optimal investment in generation.

The transmission pricing scheme adopted in China should be based on three key principles:

promoting optimal use of existing generation assets, inducing efficient siting of new generation facilities, and allocating transmission costs fairly. From an implementation perspective, it is essential that the chosen transmission pricing scheme be applied uniformly across all competitive markets in China. Broadly speaking, three transmission pricing approaches may be considered:

- *Postage stamp*—total allowed transmission revenue is allocated among network users either in proportion to their peak demands and installed capacities, or in proportion to their energy production and consumption. Postage stamp schemes are easy to implement and may be adequate for systems with low growth or relatively small transmission costs. But for systems with high load growth, as in China, the disadvantage is that siting information is lost—that is, a cheaper generator located far away will have an incentive to enter the system because the large network reinforcement cost will be shared among all users.
- *Long-run marginal cost*—total allowed transmission revenue is allocated in proportion to the marginal contribution of each user to the cost of an ideal transmission network constructed to match supply and demand. The long-run marginal cost method is the closest to the “ideal” tariff because it allocates transmission costs to agents who stress the network and, as a consequence, will motivate its expansion or reinforcement. Because the method is based on economic principles, it is easy for regulators and technical personnel to understand. The method has two possible disadvantages. Because long-run marginal cost tariffs are based on an extreme set of operating scenarios, they may vary substantially from one year to the next. And in theory, long-run marginal cost tariffs require “negative” tariffs (payments to users who reduce stress on the network). These negative payments may be high, provoking opposition from users.
- *Extent of use*—costs are allocated in proportion to each user's average use of each transmission line. Because this scheme is based on the concept of use, it is intuitively perceived to be fair by most users. It also avoids the two possible drawbacks of the long-run marginal cost method—because the allocation is based

on average use, tariffs vary less from year to year. And there are no “negative” tariffs. The scheme’s main disadvantage is the lack of an economic justification as in the long-run marginal cost scheme.

Taking into account the advantages and disadvantages of each method and international experience with their application, the recommended choices for China’s transmission pricing are the long-run marginal cost method or the extent of use method. The extent of use method is less volatile than the long-run marginal cost method when the direction of power flows may vary, as is often the case with interconnections between regional and provincial markets.

It is also recommended that the chosen method of transmission cost allocation be differentiated by node. A node may be defined as a point on the transmission network where power is injected into the grid (such as a generation station) or where power is drawn from the grid (such as a load). The application of transmission tariffs by node will promote the optimal use of existing facilities and provide locational signals for future generation expansion. In its simplest form, nodal pricing would include only the cost of the entry and exit assets at the point of connection, with the balance applied in the form of a postage stamp method. In a more advanced form, nodal pricing would include an additional component to cover individual use of the transmission network. In the most advanced form, nodal pricing would be based on the supply and demand balance at each node (that is, each node would have its own common clearing price). Although the third approach may seem complex, readily available planning and computation tools and huge improvements in computer processing speeds and costs make this approach relatively simple and inexpensive to implement.

Implementing nodal transmission prices

In the initial stages of competitive market implementation, the National Transmission Corporation and its branches will be responsible for planning and expanding transmission within and between competitive markets. The challenge will be to fairly allocate the annual revenues required to cover transmission costs among system users

(generators and distributors). To do so, nodal pricing will be calculated each year to reflect embedded transmission and expansion. These nodal charges will reflect how each market participant uses the network. During this stage each generator should pay the nodal price determined to reflect their relative siting cost on the network. The nodal charge for distributors could be aggregated and averaged—if political necessity or convenience requires that a bulk supply tariff be offered to each distributor in the first stage of market implementation.

During stage 2, regulations should encourage generators to make their own investment decisions. Although transmission expansion will still be the responsibility of the transmission entity, the transmission tariff will encourage generators to invest in economically efficient sites. This can be done through an iterative process, with the transmission company publishing nodal charges for the current year and projecting future charges based on an assumed generation expansion plan. (This would be part of the indicative planning process.) Generators will use these projected charges in assessing their competitiveness. Actual generation expansion will likely deviate from the indicative plan, and the transmission company will need to adjust transmission charge projections accordingly. Because distributors and other large consumers will have access to the market in this stage, the nodal transmission prices should also apply to them. For large industrial loads, these prices will induce efficient location decisions. This transmission pricing process is well suited to China, where transmission costs may be the deciding factor for investments in cheaper distant hydropower (which requires larger transmission investments) and more expensive thermal generation (which can be located closer to load centers).

Setting connection charges

Payments and charges for interconnecting transmission networks or connecting generators (or customers) to the network are usually made through agreements that are not part of the tariff structure. In a few countries, such as Chile, connection charges are part of the general transmission tariff. But in most countries, including England and Wales, entry and exit charges are based on the costs of interconnection facilities

that, if removed, leave the network intact. These charges are spread over the economic life of the facilities. Because connection charges recover costs incurred as a result of decisions by the entity connecting to the grid, it seems economically efficient and equitable for that entity to bear those costs. Thus a separate connection charge supports the objective of fairness. The grid code will have to clearly define which assets are included in the connection charge.

Transmission Regulation and Quality of Service

Access and pricing rules for transmission should be harmonized nationwide. With harmonized transmission planning, expansion, and pricing rules, bilateral trading between competitive pool markets and their integration can take place more easily—resulting in the greatest benefit to China. This is easiest to accomplish if a state (national) regulatory agency establishes a single consistent set of transmission access and pricing rules. Some variation between regions may be allowed to accommodate differences in reform pace and readiness for change, but the national regulator should approve these variations to ensure that there are no impediments to the future integration of markets. The national regulator should also have the authority to authorize transmission tariffs.

For efficient and smooth operation of the competitive market, transmission service must be reliable. Transmission outages can lead to unmet demand and the inability to use available generation capacity. The economic costs of these failures

are often far higher than the cost of the transmission service. Transmission entities must be encouraged to ensure that availability and quality of service meet standards established by the regulator. International experience shows that a regime of penalties and rewards, regulated on the basis of allowed revenue (or income), is the most effective way to encourage transmission companies to achieve quality standards. Penalties for network service interruption or lower than expected transmission capacity availability act as a simple and strong incentive to optimize maintenance time and reduce unscheduled outages. Bonus payments may be considered when quality of service exceeds the regulator's standards.

Notes

1. Centre for Economic Policy Research, *A European Market for Electricity*, 1999.

2. The Australian national electricity market uses both the top-down and bottom-up approaches. Market access rules have been designed to support both methods of transmission expansion. Argentina has taken the lead in pursuing market-driven solutions to expanding the grid, though with limited success. See Manuel Angel Abdala and Andres Chambouleyron, "Transmission Investment in Competitive Power Systems: Decentralizing Decisions in Argentina," World Bank, Finance, Private Sector, and Infrastructure Network, *Viewpoint* 192, 1999. In the United States the three northeastern independent service operators are starting to experiment with market-driven expansion.

Chapter 5

Dealing with Market Transition Issues

Two important transition issues need to be addressed to support China's move to competitive power markets. The first concerns excess or "stranded" costs that may no longer be recoverable from market prices once competition is introduced. Stranded costs can impede market reform and threaten the financial viability of the industry if a fair mechanism is not developed to deal with them. The second issue is the exercise of market power by the generator, which may raise pool prices above competitive levels. Generation restructuring that does not consider potential market power could seriously compromise the creation of competitive power markets.

Managing Stranded Costs

Stranded costs arise from a variety of factors, including high operating costs of old and inefficient generators, power purchase agreements with high prices, removal of production subsidies, and high staffing. Stranded costs develop when such assets have a lower market value after competition is introduced than they had before. They are so named because their costs cannot be recovered through market pricing of electricity.

In a centrally planned system, plants with high embedded and operating costs can recover the costs of their services if regulatory authorities set electricity prices high enough for them to do so. In a competitive market regulators do not ensure that plants recover their full costs. Instead, investors are ensured fair dispatch based on the

prices they bid—historical costs are irrelevant. Plants that are efficient enough to be able to bid a price that allows them to be dispatched earn a market price set by the most competitive plants. Only the lowest-cost plants are likely to be dispatched.

When future income streams from an asset are expected to decline, part of the unamortized portion of the original cost of the asset becomes unrecoverable, or stranded. A fair and effective method needs to be found to allocate the costs of stranded assets so that competitive power markets can be created without distortions.

Stranded costs affect existing plants and contracts. They also create uncertainty for new investors—especially independent power producers, which may have signed long-term contracts before the reform program began. This risk can be reduced by developing a clear policy on stranded costs, with predictable effects on new contracts.

The reverse problem of stranded "benefits" can occur when plants' fixed costs are rapidly amortized due to preferential investment incentives. For example, in the past government policies allowed investors to recover their fixed costs over a much shorter period than their economic life. This may be the case for some generating plants constructed under the "new plant, new price" policy. Plants with good operating performance can make very high profits in a competitive market. These potential excess profits may be considered stranded benefits.

Sources of stranded costs in China

There are five types of stranded costs in China's power sector:

- Excess capacity exists because of inaccurate demand forecasts or surplus reserve power.
- Construction costs were too high, or a plant operates inefficiently.
- Fuel, technology, or both become uneconomical or obsolete—for example, inexpensive gas becomes available, making combustion turbines a better option than coal-fired thermal plants.
- A plant was built in the wrong location.
- Long-term fuel supply contracts with minimum take-or-pay obligations exceed current requirements.

These problems have a number of sources. One is that many generating plants, particularly those built under joint ventures or by independent power producers, are locked into long-term power purchase agreements. For some of these plants the contracted price of power (energy and capacity) is higher than the expected market-clearing price or the contracted volume of energy is higher than would be requested under economic dispatch.

Stranded costs also result when certain plants are no longer needed to meet system load or are unable to provide power competitively once other, more efficient generators are permitted to compete. Small generating plants embedded in the distribution network can also pose a stranded cost problem. Government directives can shut down inefficient or polluting small plants. But it may prove harder to close newer investments without dealing with unamortized fixed costs.

Finally, power systems in isolated small counties tend to have transmission interconnections for trade with systems in neighboring counties. Once competition lowers the cost of grid supply, some of these transmission lines may be underused.

International experience with stranded costs

Stranded costs have been a major problem in almost every country that has moved to a competitive power market. In the United Kingdom nuclear plants, which would not have been able to recover their full costs, had to be withdrawn

from the privatization program until the government found a way for the public sector to bear the plants' stranded costs.

The United Kingdom also encountered problems with coal supply contracts. Before reform, coal was supported by the government at a cost well above international levels. The government forced generators to make long-term coal contracts at high prices—a decision that made it harder for coal plants to compete against gas in the new market.

A similar problem arose in the gas sector. When it was still a monopolist, British Gas was encouraged by the government to sign high-cost, long-term gas contracts to encourage development of the North Sea gas fields. Once competition was introduced, having to purchase expensive gas caused severe financial problems for British Gas—problems that were resolved only after the company was restructured. Several years of negotiations were required to restructure these contracts.

In Spain the introduction of competition in 1998 was projected to generate up to \$13 billion in stranded costs among power companies, which had been vertically integrated before reform. The solution was to create a financial mechanism, known as *competition transition compensation*, to cover generators' costs by setting minimum prices for several years. The mechanism has severely restricted real competition because generators receive regulated, not competitive, prices. Many other countries that are implementing the European Union Electricity Directive—which opens the European market to competition in stages—are trying to find solutions to this problem.

California, which faced a similar problem, created a financial mechanism known as the *competition transition charge* to compensate generators and pass on the cost to consumers. The fee imposed on consumers creates a continuing need to regulate consumer prices and so inhibits competition. Other states in the United States are adopting similar approaches.

Dealing with stranded costs

Three aspects should be considered when dealing with potential stranded cost problems:

- Estimating the costs.

- Determining who should pay for them.
 - Developing mechanisms for dealing with long-term power purchase agreements.
- Each of these issues is examined in this section.

Estimating stranded costs

Power companies, investors, and regulators estimate stranded costs in a variety of ways. Broadly speaking, however, there are two main approaches: administrative valuation and market valuation.

Administrative approaches use forecasting, modeling, and other analytical techniques to compare the regulated market (book) values of power company assets and liabilities with their competitive market values. In other words, they compare forecasts over the remaining life of the plant under no-reform and reform scenarios. The estimate of stranded costs is the difference between the discounted net present values of the two streams of revenues minus costs.

Market valuation relies on the purchase price of the asset as determined through an asset sale. If the market value is less than the book value, the difference represents the stranded cost. Market valuation offers several benefits relative to administrative valuation, mainly by providing an unambiguous determination of stranded costs. Administrative valuation, by contrast, can lead to substantial and time-consuming disagreements. Market valuation requires that ownership be transferred from existing owners and can reduce market concentration, especially when the assets are held by the provincial power company. But asset sales may not be possible for all potential stranded costs—as in the case of power plants not owned by utilities.

Whether administrative valuation or market valuation is used, forecasts with considerable uncertainty have to be made by power companies, regulators, and possible asset purchasers. The uncertainty grows with the remaining economic life of the asset. Forecasts of the pool price are particularly difficult, because the price is market determined and depends on bidding behavior, market structure, the balance of supply and demand, the market power of large generators, market expectations, and other factors. Forecasters must take into account the likely availability of the plant and its generating costs, including fuel costs (which are likely to be lower under

reform because of competitive pressures). They must also select an appropriate discount rate for comparing the discounted present values of the projected income streams. Given the difficulty of making these forecasts, considerable disagreement has occurred between plant owners and the authorities when using administrative valuation.

Determining who should pay for stranded costs

Policymakers need to determine whether the government, plant owners, or consumers should bear the brunt of stranded costs. One way of allocating these costs is to assign them to the party that incurred them. A second is to allocate them to the party best able to pay them. The government, whose policies created the stranded cost problem, can decide to bear all the costs itself. This can be done by writing down state equity investments in the sector or by writing off a portion of the debt owed to the state.

Alternatively, plant owners can be asked to absorb the costs. Forcing plants owned by a state-owned utility to bear these costs is equivalent to having the government absorb them. Imposing these costs on private generators may be more difficult, because private generators may be unable to absorb them. Moreover, private generators may claim that they should not be asked to cover these costs, because their investments were based on prevailing sector policies and requirements.

A third method is to have consumers pay the costs through a levy on electricity or through vesting contracts that ensure generators a minimum revenue stream based on satisfactory availability. This solution is often preferred because the costs were incurred, and accepted in the past, to meet future consumers' needs. Moreover, future consumers are likely to be able to pay.

Dealing with long-term power purchase agreements

China will need to find a way to deal with the stranded costs incurred in power purchase agreements signed with independent (nonutility) generators without restricting competition in the provincial generation market. Making an annual payment based on the difference between the actual pool price and the forecast no-reform

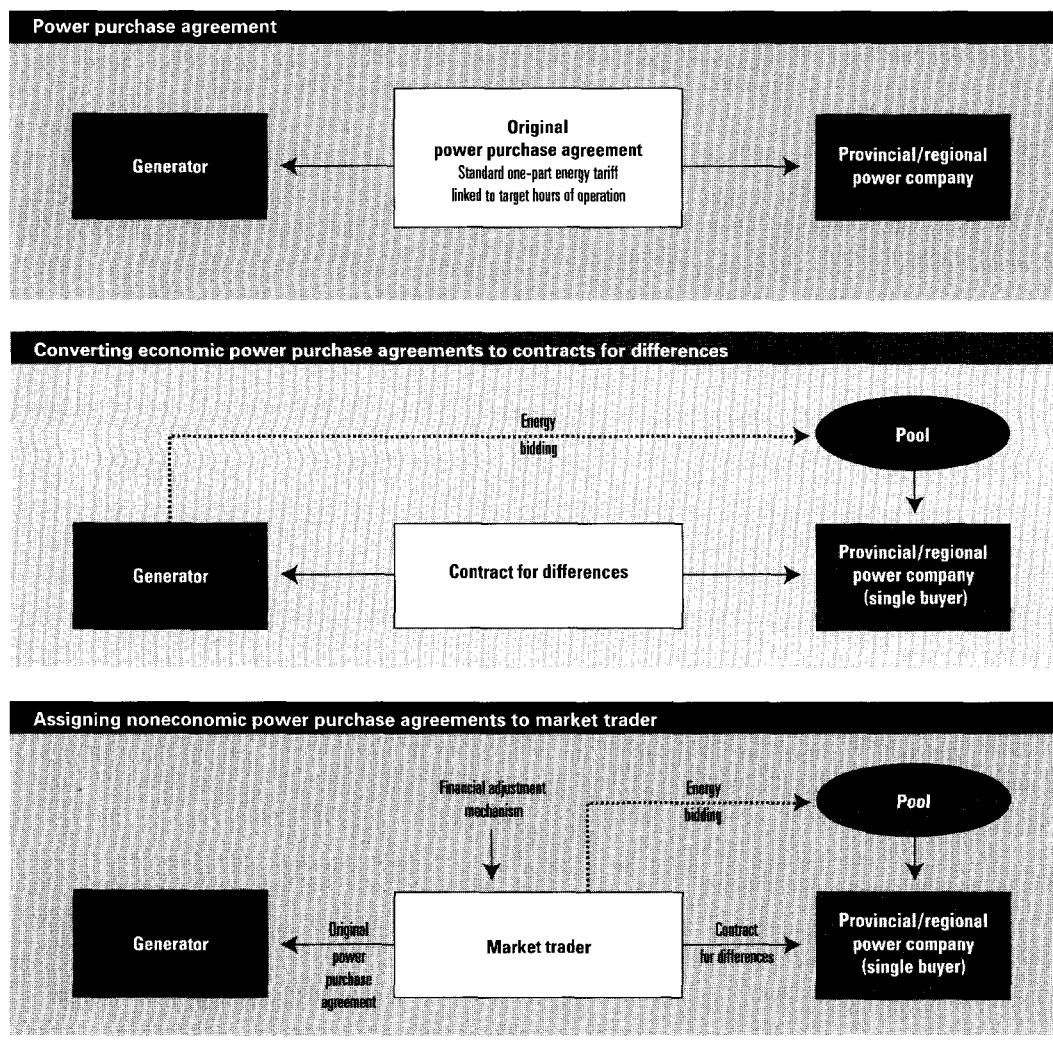
scenario would obviate the need to forecast the pool price. Any method of payment to plants that results in a fixed level of revenue, however, would reduce competition by making the plant indifferent to the pool price.

A better approach is to pay a lump sum (based on the two forecast scenarios) when the reform is introduced. The plant could then bid competitively into the pool. The first step should be to try to renegotiate the terms of power purchase agreements to make them economic.¹ The next step should be to reach agreement on changing the economic power purchase agreements into contracts for differences (figure 5.1). For each plant a contract for differences could be designed

that replicates the allocation of risks and revenues in the power purchase agreement but allows electricity to be bid for dispatch into the mandatory pool.

Power purchase contracts that cannot be transformed into contracts for differences will most likely be noneconomic and so require alternative solutions. One approach would be for these contracts to be assigned to a market trader. (The legal form of this transfer will need to be carefully considered in discussions with the parties to the contract, because it is probably not possible to transfer contracts without the agreement of both parties.) The market trader would be owned provincially, probably as a department

Figure 5.1
Renegotiating and reassigning power purchase agreements



in the provincial power company. The market trader would hold a portfolio of noneconomic power purchase contracts and bid the electricity into the mandatory pool. Under this mechanism the market trader would absorb all stranded costs—and so suffer losses. A financial adjustment would need to be made to cover these losses and ensure the market trader's long-term viability.

The costs of this financial adjustment could be borne by the government or by consumers. Either way, to satisfy the concerns of private investors in plants, credible long-term assurances would need to be provided that the trader's losses would be covered by the government or levies would be imposed on consumers to meet any revenue shortfall.

Recovering potential trading losses from consumers over time is probably the preferred and more common approach. Under this approach the regulator imposes a levy on consumer bills for a predetermined period. The levy may vary from year to year depending on the pool price, but total payments to the market trader are fixed or capped so that the trader has an incentive to bid competitively. The stranded cost is effectively converted to a debt liability, repayment of which is recovered through the levy. This method of securitizing the stranded cost liability has been used in the United States, where fresh debt securities are issued, the proceeds of which are used to compensate investors up front. Initially, securitization of stranded costs is unlikely to be used extensively in China because capital markets remain thin. Instead, the government or provincial authorities will have to provide debt finance or guarantee the liability.

Capturing stranded benefits

If the pool price is significantly higher than the price before reform, plants that have amortized or repaid their fixed capital costs will benefit from reform. The fact that fixed capital costs were amortized early indicates that customers paid too much for electricity. Providing customers with some of the excess rents these plants receive once competition is introduced can compensate them for having overpaid for power.

In China some generating plants have recovered part of their fixed costs under the “new

plant, new price” policy, which allows them to accelerate capital cost amortization. The policy can result in a front-loaded price that repays capital in the early years for plants with long expected economic lives. Any excess rents enjoyed by these plants should either be returned to consumers or used to cover stranded costs.

One way of ensuring that these benefits are returned to consumers is through a “clawback” mechanism similar to that used in Alberta, Canada. Distributors whose customers helped pay for the fixed costs of generating plants are eligible to receive a clawback. The size of the clawback is calculated by forecasting revenue flows under reform and no-reform scenarios and calculating the difference in the discounted present values of the two income streams. Under a contract signed by the generator and the distributor, the generator must deliver a specified quantity of energy to the distributor at a fixed reservation price (expected to be lower than the average pool price). Thus the contract is similar to a one-way contract for differences, with the distributor receiving a specified quantity of energy at the reservation price. During stage 1 of reform, the contract would be signed by the single buyer and the generator (with the distributor signing a supplementary agreement). In stage 2, this contract would be transferred to the distributor.

Mitigating Generator Market Power

In the power sector, the term *market power* refers to a generator's ability to raise prices above competitive levels and maintain them for a significant period. When generators with potential market power exercise this power by raising prices, it can undermine the basic objective of competitive power market reform. (The term *potential market power* is used because the generator may not actually exercise its power.) Thus it is important to mitigate market power potential at the outset when restructuring generation. A structural deficiency that leads to generator market power is a fundamental flaw that is not easily rectified through modifications to bidding systems or market rules.

Other countries have made mistakes in restructuring generation, leading to market power and noncompetitive bidding by genera-

tors. In England and Wales two dominant generating firms have kept prices well above competitive levels for years. To reduce their market power, the regulator has ordered them to sell plants and reduce their market share. A recent study of the California wholesale market determined that payments to generators during the summers of 1998 and 1999 were more than \$800 million above competitive levels.² China must avoid such problems to create generation firms that compete in the market.

A generator with market power can drive up market prices by raising its bid above its variable cost or otherwise reducing its output. The generator is able to do so under the following conditions:

- *Transmission constraints.* Transmission constraints can prevent power delivery to high-demand areas, create submarkets, and allow local generators to raise prices. A generator can create a transmission constraint by increasing its bid price until it is out of the merit order. The dispatcher must then import electricity until network capacity is reached. If demand is still unmet, the local generator is dispatched at a high price.
- *Excessive market share.* Generators with dominant market shares can raise prices because their output is required to meet demand during some hours. They can also reduce output during peak hours to bring a more expensive generating unit on line. This unit will set the pool clearing price, increasing the profits of all generators.
- *Limited number of generators.* If only a few generators participate in the market, there is increased potential for collusion and a greater likelihood that generators will learn each other's bidding strategies. A small number of generators also makes it difficult to ensure that they are all about the same size.
- *Control over peak or nonhydroelectric generation.* Generators that control the majority of peak or nonhydroelectric generation may be dominant producers during certain periods of the day. In this case the dispatcher may be forced to dispatch them regardless of their bid. A generator that has both base- and peak-load facilities may cut back on base-load plants to bring more expensive peak units on line.

- *Ancillary power needs.* Reactive power needs and dynamic stability considerations may render some plants "must run," giving them the power to charge above-market prices.

Identifying market fragmentation

Any attempt to measure or understand the potential for market power must begin with a clear geographic definition of the market area and identify whether the network or other constraints have the potential to fragment the proposed market into submarkets. Although a province is a single market, the transmission network may be unable to accommodate all power flows during peak demand hours. When transmission congestion prevents low-cost generation from reaching demand in a particular area, a local generator may have to be dispatched at a high bid. Such a generator would have potential market power.

In California congestion on a critical interconnector prevents low-cost power in southern California from meeting demand in northern California. As a result the dominant generator in the northern part of the state can bid high, because it must be dispatched to satisfy demand. In Chile the power system is served by two poorly connected transmission grids. Thus two individual markets—rather than a single market—must be examined for market power.

Measuring market concentration

Market concentration is the degree to which a few generators in the system control a dominant market share. Highly concentrated markets are more likely to have participants that exercise market power. Hence measuring market concentration can be a proxy for gauging the competitiveness of a market. The Herfindahl-Hirshman index is the most common measure for determining the extent of market concentration. The index is defined as the sum of the square of each generator's market share (calculated based on the installed generation capacity of each market participant). The index ranges from a maximum of 10,000 (or 100^2 , for a perfect monopoly) to a minimum of almost 0 (for a market with many participants).

Table 5.1 presents Herfindahl-Hirshman indexes for 19 markets. The ideal Herfindahl-

Table 5.1

Actual and ideal Herfindahl-Hirshman indexes for selected markets, 1998

Market	Number of generators	Largest market share (percent)	Actual Herfindahl-Hirshman index	Ideal market share (percent)	Ideal Herfindahl-Hirshman index
California	40	23	1,098	2.50	250
Argentina	38	14	565	2.63	263
England and Wales	32	28	1,664	3.13	313
Colombia	26	24	1,398	3.85	385
New England (United States)	16	32	1,790	6.25	325
Brazil	14	25	1,493	7.14	714
Alberta, Canada	12	55	3,791	8.33	333
Australia (national electricity market)	11	18	1,218	9.09	309
Sweden	8	52	3,226	12.50	1,250
Spain	8	46	3,361	12.50	1,250
Peru (northern interconnected system)	8	35	2,294	12.50	1,250
Czech Republic	6	75	6,007	16.67	1,367
New Zealand	6	68	5,296	16.67	1,367
Bolivia	6	26	1,887	16.67	1,367
Chile (central interconnected system)	4	60	4,256	25.00	2,500
Chile (northern interconnected system)	4	43	3,260	25.00	2,500
Northern Ireland	4	48	3,271	25.00	2,500
Portugal	3	93	8,614	33.30	3,333
Queensland, Australia	2	76	6,351	50.00	5,000

Hirshman index in each market assumes that all firms are of equal size—something that may not be possible to achieve in all markets.

The index should not be used as a benchmark to determine whether market power is likely to exist, because the index does not reflect the market shares of firms in the industry. A system in which four generators each hold a 25 percent market share and one in which one generator controls 45 percent of the market and three generators split the rest equally would both have indexes of 2,500. Although there is greater potential for market power in the second case than in the first, the Herfindahl-Hirshman indexes are identical. Few markets come close to achieving the ideal Herfindahl-Hirshman index or market share.

Estimating potential price markups

It is useful to have some estimate of how a particular market structure could affect prices. This can be approximated using the Lerner index, defined as the percentage increase in price above marginal costs. The Lerner index (the left-hand side of the equation below) is equal to the Herfindahl-Hirshman index divided by the price elasticity of demand.³

$$\frac{P - MC}{P} = \frac{HHI}{E}$$

The price elasticity of demand for electricity, E , measures how much the quantity demanded changes if its price changes. In other words, it is a measure of how much more (or less) electricity consumers would purchase when the price of electricity falls (or rises). Elasticities differ substantially across types of consumers, with industrial demand more elastic than residential demand. Increasing the number of generators can dramatically reduce the markup of market price over marginal cost. To see how, assume that the aggregate price elasticity of demand ranges from -0.5 to -0.7 . Using a Herfindahl-Hirshman index of 2,500, the price markup over marginal cost is 25–100 percent. Using a Herfindahl-Hirshman index of 1,000 and the same elasticity range, the price markup is 16–25 percent.

This relationship between the Herfindahl-Hirshman and Lerner indexes can be used as a simple guide to estimate price markups. But because the Herfindahl-Hirshman index masks inequalities in market share, the price markups obtained using this approximation should be

treated merely as indicative of the magnitude—not as exact measures.

Determining the distribution of plant assets

The distribution of base-, mid-, and peak-load plants may also be a source of market power. In general, the smaller is the difference between price and marginal cost in a given trading period, the larger is the market power of a generator that owns other plants where the price and marginal cost differential is higher. That is, generating firms that own multiple plants may be able to use their market power to reduce output and earn excess profits.

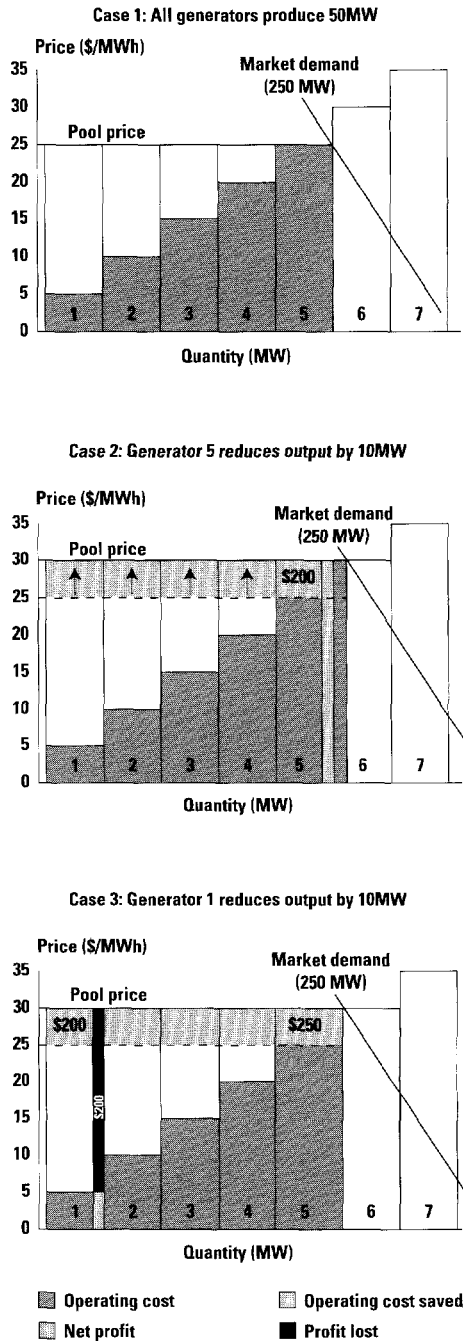
Three cases illustrate this point (figure 5.2). In case 1 each producer generates 50 megawatts at an incremental (marginal) cost of \$5 a megawatt-hour. The market-clearing price, P_c (\$25 a megawatt-hour), is set by generator 5, which earns no profit (price equals cost). The quantity demanded is Q_c . If, as in case 2, generator 5 reduces output by 10 megawatts in an attempt to bring generator 6 online, thereby increasing the clearing price to \$30 a megawatt-hour, it earns a profit of \$200 [(\$30 - \$25) x 40 megawatts]. In case 3 generator 1 attempts to exercise market power by reducing its output by 10 megawatts but gains nothing by the move—its revenue increase from the pool price [(\$30 - \$25) x 40 megawatts = \$200] equals the amount it loses from reducing output [(\$25 - \$5) x 10 megawatts = \$200]. In this case, although generator 6 comes online and the market-clearing price rises to \$30 a megawatt hour, the real winner is generator 5, which gains \$250 in profit. Generator 2 and generator 4 also gain from the higher price. If a single firm owned both generator 1 and generator 5, it could strategically reduce availability from generator 1 in order to earn \$250 on the output of generator 5.

Modeling techniques to predict market behavior

Examining market concentration, the Herfindahl-Hirshman index, and the generating mix provides insights on the potential exercise of market power. But a sophisticated computer model of the market may be required. A popular approach is to use modeling techniques based on a Cournot-Nash

equilibrium analysis of the power market using actual cost and production data, information about transmission constraints, and demand forecasts to determine when market power will be exercised.⁴

Figure 5.2
Exercise of market power by firms with multiple plants



The model assumes that generators select a profit-maximizing output given competitors' choices and that they are most likely to exercise market power during peak demand hours, when most generators are fully dispatched, leaving residual demand to a few dominant players. The dominant generators can reduce output to bring expensive producers online, raising the system-clearing price. In any given period, high-demand hours should be examined to determine which generators will be dispatched and how much the pool-clearing price will rise. The Cournot-Nash equilibrium model allows policymakers to examine the potential for market power under a variety of market conditions.

A study of California's system examined market power under three levels of demand elasticity, several proposals for divesting assets, increased production of hydropower, integration of regional electricity supply, and several degrees of transmission congestion.⁵ It may be valuable to undertake similar modeling exercises in China. In addition, the model should be used to determine when and to what extent divestiture plans, seasonal factors (such as wet and dry periods), and transmission congestion will allow generators to exercise market power.

Restructuring the generation industry

The structure of the generation industry—in terms of concentration, asset distribution, and firm size—is the most important determinant of generation market power. Getting the generation industry structure right is the best way to mitigate market power. The following strategies should be considered:

- *Increase the number of competitors—but limit the size of the largest participant relative to other participants and to the extent possible ensure that all competitors are of similar size.* Regardless of how many firms compete in the market, market share should be distributed as equally as possible. But maximizing the number of generators will not guarantee competition if dominant players emerge. Nearly 35 generators operate in England and Wales, but 2 have always controlled a major share of the market. Between April and November 1998 these two generators set the market-clearing price almost 65 percent of the time. In California about 40

generators bid into the pool, but Pacific Gas & Electric and Southern California Edison continue to hold the largest market shares. Many countries—Argentina, Brazil, Panama—have placed ceilings on the market share of installed capacity, usually allowing no single firm to own more than 25 percent of total capacity.

- *Allocate generation assets equally across participants.* In England and Wales two generators often set the market-clearing price because nearly all the mid-merit plants are in the hands of two or three generators. Some facilities, such as many base load plants, lack significant market power. But others, such as hydropower assets, may hold significant market shares in certain markets, such as spinning reserve. These ancillary markets should be examined to ensure that certain generators do not dominate the market for certain services.
- *Mitigate opportunities for collusion by separating power plants into as many separately owned companies as possible.*

Incorporating remedies for market power in market rules

Apart from the structural remedies—which are preferred for addressing market power concerns—a variety of regulatory remedies can be applied once the market is operational:

- *Limitations on variance of bid prices.* In competitive markets, bids for running individual units should not vary with market conditions (although market prices will). To mitigate market power, a generator with market power potential could agree to limited bands for bidding each unit.
- *Denial of market-based prices.* In extreme circumstances, when there is evidence showing that generators are exercising market power, the regulator should be given the right to deny them market prices and offer them cost-based rates or a pre-established ceiling price. However, the denial of market-based pricing risks undermining incentives for competitive markets—and so is a remedy that should be used sparingly.
- *Requirements for transmission upgrades.* Generators could be required to contribute to transmission upgrades in load pockets where they operate to mitigate market power potential.

- *Monitoring that can detect and penalize generators that exercise market power.* The regulator should have ready access to bids and price outcomes so that it can investigate complaints of suspicious or anticompetitive behavior by generators or dispatchers. The regulator should be able to impose appropriate penalties if evidence of market abuse is discovered.
- *Simple and efficient open bidding procedures that are applied as close to real time as possible.* To prevent manipulation of the market and misrepresentation by individual generators, the bidding procedures and rules should minimize opportunistic revision of bids by generators. For example in the England and Wales market, it was found that one of the dominant generators used to declare a number of plants unavailable in order to raise the capacity payment. Once the capacity payment had been determined, the generator declared the units available, making them eligible to receive the higher capacity payments. In addition, rules with low bidding costs and few bidding restrictions encourage entry. Even if there are initially only a small number of generators in a provincial market, the behavior of dominant players may be kept in check by the threat of potential competition from new entrants. Simple and transparent rules are usually best, because they minimize the costs of participation.

Finally, it is worth recognizing that the possibility of creating a competitive pool of generators without market power is severely limited in small systems. Specifically, when the peak load is less than 1,000–1,500 megawatts and a few generators serve the market, it may not be possible to create the conditions necessary to mitigate generator market power if a price-based power pool market structure. The relationship between the Herfindahl-Hirshman and Lerner indexes

demonstrates that the smaller the number of firms, the larger the price markups are likely to be. This effect is magnified when one firm holds a dominant share of the market. In Northern Ireland, where four generators compete, the largest generator controls nearly 50 percent of the market. Consequently, a single buyer system with economic cost-based dispatch has been adopted in Northern Ireland to prevent collusion and mitigate market power. In summary, alternatives to a pool-based market with price competition should be considered when the market size and number of generators are very small.

Notes

1. The government may be willing to write down the asset values of government-owned plants and lower contract prices accordingly. For private investors, it would be extremely difficult to lower the value of the contract significantly without threatening the sanctity of the contracts (something China has declared it will not do), thereby jeopardizing China's standing with international investors.

2. U.S. Department of Energy, "Horizontal Market Power in Restructured Electricity Markets," Office of Policy, Washington, D.C., 2000.

3. The equation assumes that generators strive to achieve a Cournot equilibrium, in which each firm chooses its output to achieve a market-clearing equilibrium. This assumption is reasonable given that generators use a quantity strategy to maximize profits.

4. See note 3.

5. Severin Bornstein, James Bushnell, E. Kahn, and Steven Stoft, "Market Power in California Electricity Markets," 1996, University of California Energy Institute, Berkeley, 1996 (available at <http://www.ucei.berkeley.edu/ucei/>).

Chapter 6

Regulating Power Markets

China's power sector is controlled by various state, provincial, and subprovincial agencies. The functions and responsibilities of these agencies often overlap and are based on a "command and control" approach that is unsuitable for an industry moving toward increased competition. It is essential that institutional arrangements be reformed and adapted to competitive pool markets, open access transmission systems, and bilateral trading arrangements between competitive pool markets.

A regulatory framework to support effective competition within competitive pool market areas, active bilateral trading between them, and their gradual integration will require capable institutions at the state and lower levels. Regulatory processes must be clear, credible, and responsive to the changing demand for regulation as the market transition proceeds. Strong coordination between state and local regulators would ensure consistent and smooth market development.

Creating such a framework will require fundamental changes in the way government agencies supervise and intervene in power operations. This chapter answers three fundamental questions that will guide the design and implementation of the regulatory framework: what is to be regulated, who should regulate, and what legal provisions are needed. This chapter builds on an earlier report prepared jointly by the former Ministry of Electric Power and the World Bank.¹

What Is to Be Regulated?

During stage 1 of implementing competitive pool markets at the regional and provincial levels, the regulatory authority will need to control the activities of the purchasing agent, the transmission entity, and the distribution entities. It will also need to supervise the contracts and contracting processes managed by the single buyer. As the stage 1 mandatory pool with single buyer structure evolves to wholesale competition, the regulation of contracts may be relaxed, although some additional regulatory arrangements will be required.

Regulating the activities of the purchasing agent

The presence of the purchasing agent within the competitive pool market is a transitional step until wholesale competition is introduced. During this transition the purchasing agent will have monopsony power to sign the initial contracts for differences with generators. Regulation should ensure that the purchasing agent signs these contracts in an efficient manner—that is, without discriminating between generators or agreeing to contract prices that are inefficiently high or unreasonably low.

The purchasing agent will also be participating in the bilateral power trading between competitive pool markets. The regulator should supervise these trades to ensure that the purchasing agent takes advantage of transaction opportunities to meet an "efficient purchase" obligation.

Other activities of the purchasing agent that must be regulated include purchasing ancillary services from generators, contracting for transmission use of system services, bundling its own and purchased services, and applying a bulk supply tariff to the sale of power to distributors.

Regulating the activities of the transmission entity

As market implementation proceeds, generation will be completely separated from transmission—beginning first with management separation into independent business units and then separate ownership. Apart from minimizing (if not entirely eliminating) conflicts of interest, this separation will also simplify the activities of the regulator.

The following transmission activities must be regulated:

- *Expansion of the transmission system.* The transmission entity must be regulated to ensure that it makes optimal investment decisions that take into account standards of service quality and security. In addition to authorizing investments in transmission system expansion, the regulator may need to take an active approach to encouraging expansion. To support timely transmission expansion, the regulator may have to help obtain needed rights of way.
- *Service quality and reliability.* The regulator needs to ensure that appropriate supply quality and reliability standards are achieved—that costs are minimized without reducing quality below an acceptable level. The regulator will also determine and apply penalties for non-compliance with service quality and reliability obligations.
- *Transmission tariffs and pricing.* The regulator should approve transmission tariffs to ensure that the revenues earned by the transmission entity cover the costs of the embedded system and expansion needs. To create incentives for efficiency, the regulator will have to establish efficient cost benchmarks.
- *Access to the transmission system.* The regulator needs to ensure that market participants are given fair access to the transmission system. Transmission connection and use protocols should be approved by the regulator. Disputes will also have to be handled by the regulator.

Regulating the activities of distribution entities

Distribution within competitive market areas will mainly be conducted by municipal, prefectural and county power supply bureaus. Regulation must cover the retail services of all these distribution entities. Most power supply bureaus also own and operate local power plants (embedded generation), creating additional regulatory issues. Regulation must also distinguish between independent power supply bureaus and bureaus that may initially be owned by the transmission entity (that is, bureaus that are part of existing regional or provincial power companies).

At a minimum, regulation of the power supply bureaus must cover their trading and transportation activities. This regulation would cover the following areas:

- *Consumer price and quality of service.* The price and quality of services provided to consumers, including retail tariffs, supply quality and reliability standards, consumer service standards, obligations to connect and serve, energy efficiency promotion and demand-side management programs, and other consumer issues, such as the protection of poor and vulnerable consumers and procedures for handling complaints.
- *Overall efficiency and financial performance.* Power supply bureaus should have their allowable distribution costs benchmarked to ensure that they are operating efficiently.
- *Expansion of the distribution system.* The regulator would have to authorize major investment decisions and, if necessary, ensure an active approach to system expansion.
- *Efficient wholesale energy procurement.* As the market develops, power supply bureaus will begin to contract directly with generators for energy and capacity. The state regulator will have to determine when and how power supply bureaus will be permitted to procure their energy requirements directly and conclude contracts for differences and other hedging instruments to manage price risk and meet demand efficiently. Additional regulation will be needed to ensure that bulk power procurement is done efficiently. This may be achieved by setting clear guidelines on the pass-through of wholesale power costs.

- *Pricing of distribution network services.* Power supply bureaus will gradually have to provide access to their networks as large consumers begin to contract directly. The terms of access will have to be established and authorized by the regulator.

Regulator’s relationship to the system and market operator

Under the proposed reform, day-to-day operation and administration of the competitive pool market and bilateral trading between markets will be the responsibility of the designated system and market operator, whose roles and responsibilities will be defined in the market rules. From the perspective of supervising the market, the market operator has primary responsibility for dealing with operational disputes, while the system operator deals with operational emergencies through processes laid down in the market rules. The regulator approves the market rules and changes to the rules, monitors administration and operation of the rules, collects all information needed for monitoring market participants, arbitrates disputes referred to it, investigates the rules when necessary, and approves emergencies and suspensions as required by the rules. Although the regulator is responsible for developing and enforcing the rules, the market should be as self-regulating as possible. In other words, the regulator should aim to act only when necessary to ensure the equitable and efficient operation of the market. Table 6.1 summarizes the allocation of responsibilities between the regulator and the system and market operator

It has been suggested that the system operator and market operator functions be established within the regional or provincial transmission

entity (that is, the residual regional or provincial power company) in the competitive pool market area. If the regional or provincial power company maintains even a small ownership role in generation, the market operator and system operator functions will not be perceived as impartial by independent generators, and their authority to administer market rules will be undermined. These conflicts will be avoided when generation is totally separated from the transmission entity. During the interim, the regulator will have to be more vigilant and responsive to complaints from generators who perceive a bias in the system and market operator.

In addition to monitoring the administration of the market rules, the regulator has authority over other market issues, including anticompetitive behavior by participants, mergers of participant generators, and other structural changes. To prevent mergers and anticompetitive behavior from hindering market development, the regulator must establish guidelines for mergers and retain the right to deny approval of mergers it believes will increase the potential for horizontal market power. The regulator should also have the power to intervene if anticompetitive behavior, such as collusion or predatory pricing, takes place; impose fines in the case of noncompliance with regulations; and prevent attempts by participants to limit competition from generators outside the competitive market area.

Who Should Regulate?

The question of who should regulate an industry raises fundamental questions of power and authority over politically and economically sensi-

Table 6.1

Proposed division of responsibilities between the system and market operator and the regulator

System and market operator	Regulator
<p>Market operator</p> <ul style="list-style-type: none"> ■ Proposes the market rules and changes to the rules through processes laid down by the regulator ■ Acts as market implementing and operating agency ■ Deals with disputes through processes laid down in the rules 	<ul style="list-style-type: none"> ■ Approves the market rules and changes to the rules ■ Requires rule changes if necessary ■ Monitors administration and operation of the rules ■ Collects all information needed for monitoring market participants ■ Arbitrates disputes referred to it ■ Investigates the rules when necessary ■ Approves suspensions and emergencies as required by the rules
<p>System operator</p> <ul style="list-style-type: none"> ■ Handles emergency and supervision issues as indicated in the rules 	

tive issues. Regulation of the power sector is particularly difficult because, like other infrastructure sectors, it is strategically important and many regulatory bodies at different levels of government already regulate the sector.

Currently regulatory decisionmaking on electricity pricing and investment requires the approval of many agencies at the state and local (typically provincial) levels. Provincial agencies are also involved in electricity regulation at the municipal and county levels (county pricing bureaus). Overlap of roles and responsibilities extends to policy and regulatory functions as well. At the state level, for example, both the State Economic and Trade Commission and the State Development Planning Commission perform important policy and regulatory functions.

While some regulatory roles and policymaking functions overlap, other regulatory functions do not appear to be explicitly assigned to any of the existing external regulatory agencies. Establishment of quality standards and security obligations, for example, does not appear to be explicitly assigned to any agency.

It is beyond the scope of this report to define the institutional framework for regulating competitive power markets. It is clear that a state-level regulator will be required to establish the basic rules and procedures for implementing, operating, and supervising competitive markets and trade between them. It is also clear that to be effective and responsive, the state regulator will require lower-level agencies or branches to conduct regulatory functions at the level of the regional or provincial competitive power market. But it is not immediately clear how the state regulator will establish lower-level regulators and maintain a consistent regulatory framework throughout the country. These issues will have to be defined through detailed institutional studies. The following discussion provides some guidance on the delineation of responsibilities between the two levels to achieve effective supervision of competitive power markets and eliminate overlapping responsibilities.

Distinguishing the roles of state and lower-level regulators

In delineating the roles of state and lower-level (regional or provincial) regulators, it is suggested

that key investment and pricing decisions be made by the lower-level regulatory entities based on principles approved at the state level. These lower-level regulatory entities should be established as direct affiliates of the state regulator. In the interests of effective and responsive regulation, lower-level regulatory bodies must be able to make decisions quickly, taking into account specific local circumstances and issues—something state agencies based in Beijing will not be able to do. But lower-level regulators must use standard methodologies and guidelines issued by the state regulator. This would allow the state regulator to ensure a consistent and coordinated approach to market implementation, operation, and supervision. Such consistency will also facilitate the gradual integration of markets. Table 6.2 offers a proposed division of responsibilities between state and lower-level regulators. In addition, the state regulator may continue to regulate the State Power Corporation of China.

The state regulator may continue to be involved in investment decisions for large projects in order to ensure that financing follows the guidelines of the State Development Planning Commission and Ministry of Finance. The state regulator's direct involvement and approval should be required only for issues concerning trading between competitive market areas. That would include transmission expansion between markets, bilateral trading rules, and the operation of National Transmission Corporation (that is, the reorganized State Power Corporation of China). In addition, the state regulator should ensure that the capacity of the transmission network is adequate at all levels and that access and pricing rules are fair and efficient.

Separating regulation from policymaking

Most countries that develop explicit regulatory frameworks for power separate institutional responsibility for policymaking and regulation. In Australia, Poland, Thailand, and the United Kingdom, for example, the ministry (and the government) retains responsibility for policymaking, while regulation is handled by an autonomous regulatory agency. An appropriate starting point in China might be to divide the power department of the State Economic and Trade Commis-

Table 6.2

Division of responsibilities between state and lower-level regulators

State regulator	Lower-level regulators
<ul style="list-style-type: none"> ■ Establish principles and detailed guidance on development and implementation of competition ■ Approve the market rules for individual competitive pool markets and ensure consistency for future market integration ■ Establish common principles and methodologies for transmission access, transmission pricing, and consumer tariff-setting ■ Establish regulatory procedures for reviewing and authorizing investment plans and resolving disputes ■ Formulate model contracts and licenses and issue service quality standards ■ Regulate power trade between markets. Establish protocols, bilateral trading rules, and transmission tariffs for intermarket trade ■ Approve the accounts and investment plans of the National Transmission Corporation and its branches 	<ul style="list-style-type: none"> ■ Regulate consumer tariffs, including transmission tariffs within the market, subject to central guidelines ■ Approve investment plans of the transmission entity and distributors within the market; implement and monitor market service quality ■ Resolve market disputes ■ Review the accounts of the transmission company and distribution enterprises (power supply bureaus) ■ Review and approve contracts of the purchasing agency

sion into two groups, one for policy and one for state-level regulation of the industry. The same separation could be done within the State Development Planning Commission.

To lay the foundations for an autonomous state-level electricity regulator, the regulatory group in the State Economic and Trade Commission might then be merged with the (regulatory) departments of the State Development Planning Commission responsible for electricity pricing. In addition, the policy role of the State Economic and Trade Commission could be combined with that of the State Development Planning Commission—and if possible assigned to one of the two agencies. This issue deserves more detailed study.

Regulatory Capacity-Building Implications

Providing effective regulation in a competitive market environment will place considerable demands on institutional, staffing, and skills requirements. These requirements extend to the regulated companies in addition to the power sector regulatory agency. The difficulties of recruiting and retaining staff with the skills to carry out such regulation should not be underestimated.

Table 6.3 provides information on staffing levels among the electricity regulators of vari-

ous countries. It has been suggested that it is difficult to have effective regulatory capability with fewer than 30–40 professional staff. These represent the fixed costs associated with establishing license approval and monitoring and enforcement procedures. Beyond these fixed costs, regulatory staff requirements depend primarily on the number of companies to be regulated and the type and complexity of competitive arrangements in the sector. In the United States, for example, the Federal Energy Regulatory Commission has more than 400 professional staff working on the equivalent of central-level regulatory issues. In addition, each U.S. state (equivalent to a province) has its own public utilities commission with several staff working on electricity regulation.

What Legal Provisions Are Needed?

Power regulation must be founded on a firm legal basis if it is to inspire confidence and support the development of competitive markets. In 1996 China passed an Electricity Law that established new legal provisions for the power sector. Nonetheless, the pace of the anticipated changes in the power sector requires that the Electricity Law be substantially revised. While the law allows for some evolution of the sector, it poses a serious constraint to future reforms.

Table 6.3

Electricity regulators in various countries

Country	Regulator	Number of staff	Size of system (megawatts)
Argentina	Ente Nacional Regulador de Electricidad	141	20,600
Brazil	National Agency of Electrical Energy	325	60,800
Chile	Comisión Nacional de Energía (includes gas)	40	7,500
Colombia	Comisión Nacional de Regulación de Energía y Gas (includes gas)	35	10,800
Malaysia	Department of Electricity and Gas	150	11,800
Mexico	Comisión Reguladora de Energía	145	37,600
Philippines	Energy Regulatory Board	200	8,700
Singapore	Public Utilities Board	101	5,600
Spain	Comisión del Sistema Eléctrico Nacional	74	41,700
United Kingdom	Office of Electricity Regulation (Offer)	252	70,500

Source: Jon Stern, "Electricity and Telecommunications Regulation in Developing Countries," unpublished manuscript.

Market implementation limits under the Electricity Law

The 1996 Electricity Law allows for market structures that include single buyers purchasing power based on long-term power purchase agreements—and indeed, such markets operate today in China. The power sellers (generators) may be required to compete to determine which will be selected and have the opportunity to negotiate a power purchase agreement with the single buyer; thus the law supports competition for the market. It also appears that the law allows for the formation of a mandatory pool with a single-buyer structure (stage 1 of the transformation). That is, the law does not dictate how wholesale prices are to be established by single buyers, so stage 1 would be possible.

Stage 2 is a wholesale market in which both distributors and large customers would have a choice of supplier. For two reasons, there are limits to moving to stage 2 under the current law. First, the law does not contemplate power purchases by either large or small customers except from their current suppliers. While it may be possible to infer that distributors would have a choice about where they would purchase the power to meet their supply obligations, it seems to be the intention that all consumers are to be supplied by the franchised distributor. Second, the law does not provide for adequate regulation—both the institutions and the functions—to support broad wholesale competition. Thus a

limited stage 2 (with distributor choice) may be possible under current law. Stage 3, retail competition, cannot be implemented without a change in the law.

In summary, while reform can continue, revisions in the law should proceed in parallel. Indeed, although one may conclude that the law supports stage 1 and perhaps a limited version of stage 2, it would be preferable to have proper regulation in place as soon as possible. Indeed, the better approach would be to enact a new law—one that specifically anticipates the evolution of the sector—before any move to stage 2.

Revising the Electricity Law

The new law should identify the overall objectives for the sector and the role (or functions) of the regulatory authority to facilitate the achievement of those objectives. The law should also lay out the relationships between the state-level regulator and lower-level regulators. There are useful lessons from other countries that have had to deal with similar issues.

The identification of the objectives will guide the regulatory agency in making regulatory policy and in rendering its decisions. For example, the objectives could include the creation, promotion, preservation of an efficient industry and market structures; the promotion and implementation of competition; the facilitation of private sector participation; the assurance of an adequate power supply and maximum access; properly

established tariffs; and the maintenance of reliability and safety. To satisfy these objectives, the regulator would need to be assigned specific functions and given adequate authority to establish a proper licensing and tariff-setting authority, set performance standards for licensees and monitor power markets, and establish the rights and obligations of consumers.

Given the complexities of these tasks, regulators will need to be individuals with skills, experience, and integrity. Thus the law should set standards for their appointment and possible removal. Part of the state's commitment to reform will necessarily include proper budget support for regulators, which should also be articulated in the law. It is widely accepted that regulatory independence requires the appointment of high-quality individuals who are properly supported and who are able to make difficult, sometimes controversial decisions without interference.

All participants in the sector—in generation, transmission, distribution, and supply—should have licenses (sometimes called business permits) identifying their responsibilities. The regulator

should establish the terms and conditions of licenses, the technical and commercial codes to be followed, the rights and obligations of consumers, and the prices to be charged for service. The license obligations should be monitored and enforced by the regulator; inadequate enforcement of licensee responsibilities will cause consumers and government to lose confidence in the regulatory regime.

China is undertaking power sector reform within the context of broader market reform. Thus, as the drafting of a new Electricity Law proceeds, it would be useful to simultaneously address the changes required in other laws—such as property, contract, and company laws—to facilitate the flow of investment and the ability of licensees to carry out their responsibilities.

Note

1. World Bank, *China: Power Sector Regulation in a Socialist Market Economy*, Discussion Paper 361, 1997. (This report was also published in Chinese.)

Annex

The Contract for Differences

A contract for differences (CfD) is a financial instrument that provides a buyer and seller of electricity with a constant, negotiated price (the strike price) for an agreed quantity. The contract eliminates vulnerability to the significant price fluctuations that occur in the hourly spot market for electricity.

In an energy pool the seller of electricity always receives and the buyer always pays the clearing price. In a CfD, if the clearing price is below the contract's strike price, the buyer pays the difference to the generator. If the clearing price is above the strike price, the generator pays the difference to the buyer (figure A1).

In addition to providing buyers and sellers with a hedge against price volatility, a CfD provides generators with incentives to bid their real marginal cost. As long as the generator cannot manipulate the pool price by exercising market power, a CfD provides a strong incentive to achieve optimal dispatch. It also provides generators with incentives to increase efficiency and reduce marginal costs, so that they can lower their bids and increase the proportion of time they are dispatched. Increasing their rate of dispatch is desirable because they receive payments equal to the difference between the pool price and their marginal cost every time they are dispatched.

Determining the Pool-Clearing Price

Assume that the energy pool has commenced operation and that each power plant is required

to submit its dispatch bid to the market operator. The market operator collects the bids from each generator and stacks them in order of their bid price, from lowest to highest (figure A2).

The bid stack is then compared with system demand, with the last generating unit in the stack needed to supply the demand identified as the marginal unit. The bid price of the marginal unit—known as the pool-clearing price (P_p)—is published to inform all market participants and interested parties of the current price of electricity.

The physical market and the financial market are linked by the common clearing price. Since the physical market produces a clearing price each

Figure A.1
Payments to buyer and generator under a contract for differences

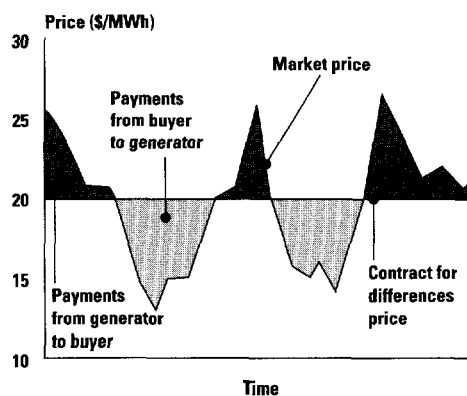


Illustration of a Contract for Differences

Four cases illustrate how a CfD creates good economic incentives and ensures that generators earn adequate revenues.

Case 1: The marginal generator

In case 1, G5's variable costs are \$25 per megawatt hour, its maximum output is 100 megawatt hours, and its minimum output is 20 megawatt hours. It produces 80 megawatt hours of output and receives the pool-clearing price of \$25 per megawatt hour.

Assume that G5 has contracted to provide 80 megawatt hours of output each hour to the buyer at a contract price of \$30 per megawatt hour. The generator provides the buyer with 80 megawatt hours of its own output at a pool-clearing price that is lower than the contract's strike price, and the purchaser refunds the difference to the generator. The revenue obtained from the market by any generator is given by:

$$Y_g = Y_e - Y_{cfd} = (V_e \times P_p) + [Q_c \times (P_c - P_p)]$$

That is, G5's revenue is the sum of the revenue from selling output into the generation pool (Y_e) and the revenue from the CfD (Y_{cfd}). V_e is the quantity sold into the pool (up to a maximum of 100 megawatt hours); Q_c is the contract amount (80 megawatt hours).

The generator's net revenue (π) is simply its total revenue minus its variable cost of production (P_v) per unit of output:

$$\begin{aligned} \pi &= Y_e + Y_{cfd} - (P_v \times V_e) = (V_e \times P_p) \\ &\quad + [Q_c \times (P_c - P_p)] - (V_e \times P_v) \\ &= [V_e \times (P_p - P_v)] + [Q_c \times (P_c - P_p)]. \end{aligned}$$

For the marginal generator, the pool price is equal to variable cost. At this price the generator will earn no revenue from production revenue; it will still receive revenue from the CfD:

$$\begin{aligned} \pi &= [V_e \times (P_p - P_v)] + [Q_c \times (P_c - P_p)] \\ \pi &= [80 \times (25 - 25)] + [80 \times (30 - 25)] \\ \pi &= \$0 + \$400 \\ \pi &= \$400. \end{aligned}$$

The relationship between the revenue obtained from energy production [$V_e \times (P_p - P_v)$] and the revenue obtained from the CfD [$Q_c \times (P_c - P_p)$] is shown in box figure A1. Generator G5 is indifferent to its level of production at this pool-clearing price, because at every output level the CfD is the only element providing it with profits. The interaction between price and quantity can be regarded as a fast improvement environment because any increase in the pool price provides incentives to do better.

Case 2: The nondispatched generator

In this case, generator G5 is not dispatched above its minimum load by the system operator, because demand meets supply at a price that is below G5's bid. At all levels of production the cost of production exceeds the pool price, indicating that the generator would lose money if it bid below its production cost. If the pool prices are sustained at low values for long periods, the generator is likely to voluntarily lower its volume (by reducing its bid) and come out of service.

In this case the generator receives:

$$\begin{aligned} \pi &= [V_e \times (P_p - P_v)] + [Q_c \times (P_c - P_p)] \\ \pi &= [20 \times (20 - 25)] + [80 \times (30 - 20)] \\ \pi &= -\$100 + \$800 \\ \pi &= \$700. \end{aligned}$$

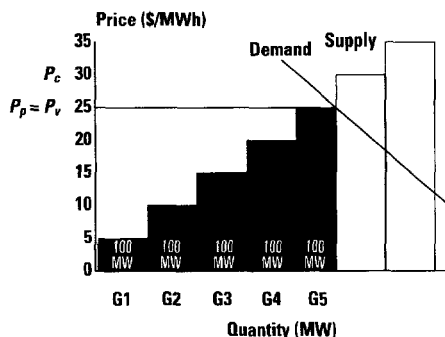
Box continues on page 72

Box figure A.1

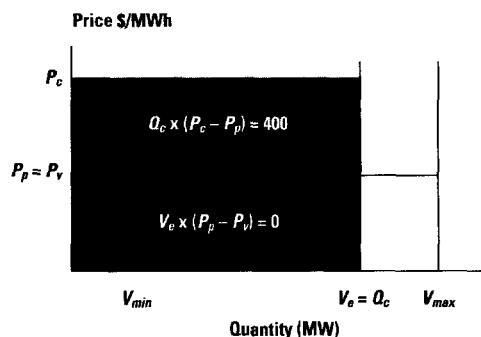
Bid price stack for an energy pool

Case 1
The marginal generator

Price received and quantity supplied by the marginal generator

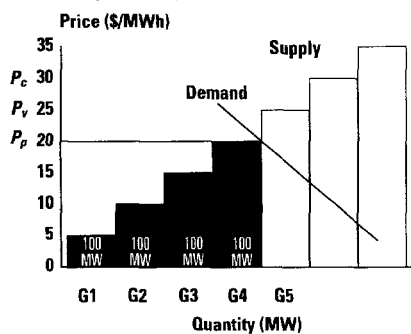


Marginal generator price and quantity

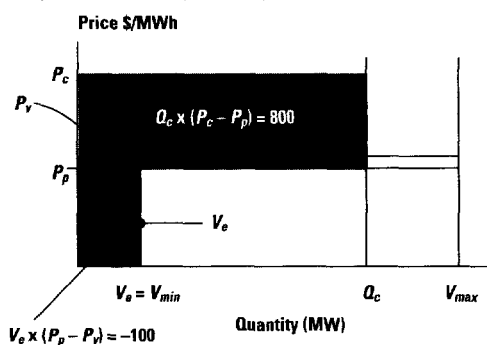


Case 2
The nondispatched generator

Price received and quantity supplied by the nondispatched generator

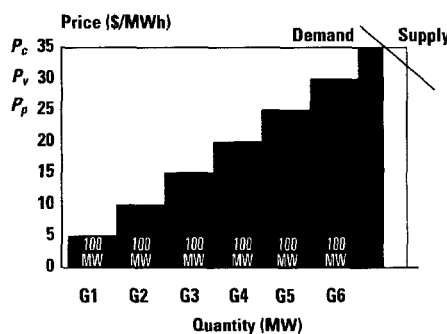


Nondispatched generator price and quantity

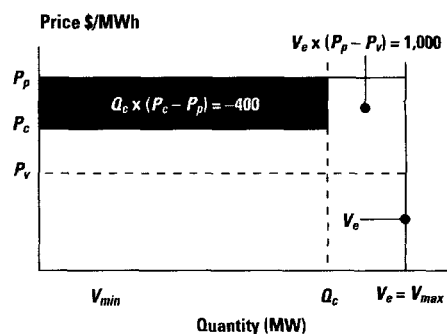


Case 3
The fully dispatched generator

Price received and quantity supplied by the fully dispatched generator

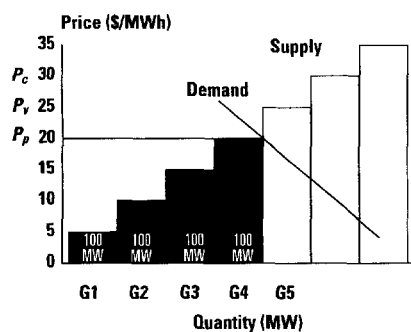


Fully dispatched generator price and quantity

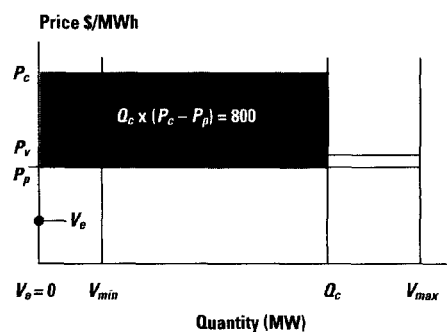


Case 4
The reserve generator

Price received and quantity supplied by the reserve generator



Reserve generator price and quantity



Note: P_c = contract price. P_p = pool clearing price. P_v = variable cost of generation. Q_c = contract quantity. V_e = quantity dispatched.

Illustration of a Contract for Differences *continued*

If the pool price rises above P_c , the CfD will reduce the revenue received by the generator. The generator will seek to return to service rather than suffer a decline in revenue.

The pool price also gives the generator three other, longer-term incentives. First, it motivates the generator to lower the minimum load level in order to reduce costs without having to come out of service (and hence incur start-up costs later). Second, it motivates the generator to lower the cost of production so that it will be able to compete for dispatch at lower pool-clearing prices. Third, it motivates the generator to lower its start-up costs in order to mitigate the costs associated with running at minimum capacity.

The market as a whole gains when G5 reduces its energy production, because this output is now produced by G4 at a lower variable cost. The market has encouraged the higher-cost unit to come out of service and be replaced by a lower-priced generator.

Case 3: The fully dispatched generator

When the pool price rises above the cost of production and the contract price ($P_p > P_c > P_v$), G5 bids to be fully dispatched, since all of its output is needed to meet the market's demand.

In this case the generator receives:

$$\begin{aligned} \pi &= [V_o \times (P_p - P_v)] + [Q_c \times (P_c - P_p)] \\ \pi &= [100 \times (35 - 25)] + [80 \times (30 - 35)] \end{aligned}$$

$$\begin{aligned} P &= \$1000 - \$400 \\ P &= \$600. \end{aligned}$$

Since net revenue is based on all energy produced, the generator has an immediate incentive to increase output up to its maximum capacity, regardless of the quantity contracted. In the longer term, the generator would have an incentive to increase its maximum capacity.

Case 4: The reserve generator

If the pool price is sustained below the variable production cost, the generator receives:

$$\begin{aligned} \pi &= [V_o \times (P_p - P_v)] + [Q_c \times (P_c - P_p)] \\ P &= [0 \times (20 - 25)] + [80 \times (30 - 20)] \\ P &= \$0 + \$800 \\ P &= \$800. \end{aligned}$$

In this case generator G5 earns no revenue from energy production; all of its revenue comes from the CfD. The generator has an incentive to stop running completely. This is similar to the situation faced by the nondispatched generator except that in this case, pool prices remain below the reserve generator's variable costs for a prolonged period.

Once the pool price rises above variable production costs, the generator will have an incentive to produce more energy. The generator will then come into service, increasing the reliability of electricity supply for the province.

half hour, a new CfD financial settlement calculation is required for each trading period as well.

The CfD process depends on the pool-clearing price, but it occurs independently of it. The CfD quantity can be shaped to meet buyers' requirements. The contract indicates the quantity of output covered by the contract in each half-hour trading period. The buyer establishes these quantities based on forecast demand patterns. Using a schematic like the one shown in figure A3, the generator can project the physical quantities needed to match the contract cover and the financial gains that will result from each transac-

tion. (The generator is not obligated to produce the exact quantity of electricity covered by the CfD. Any quantity above or below the contract is settled at the pool price, not the contract price.)

CfDs are established in advance and incorporate specific contract prices (P_c) and contract quantities (Q_c) for each half-hour trading period. The contract price need not have any direct relationship with the generator's actual marginal cost of energy production. The buyer normally links the contract price to the forecast price of pool energy to the system, with the contract price higher at peak times and lower at off-peak times.

Incentives for Generators to Bid Their Marginal Cost

The generator’s total payoff (net revenue or profit) is given by the following expression:

$$\text{profit} = [Q_c \times (P_c - P_p)] + [V_c \times (P_p - P_v)]$$

If a generator bids its marginal cost, and as a result is the marginal generator, then P_p would equal P_v and the payoff would become:

$$\text{payoff} = [Q_c \times (P_c - P_p)] = [Q_c \times (P_c - P_v)]$$

That is, the payoff is dependent on the extent that the CfD contract price is higher than the generator’s marginal cost (P_v). However, the production level (V_c) would vary from minimum load to maximum load, depending on the level of the demand. Assume that the level of the demand has resulted in the marginal generator being at minimum load.

Assume that this level of demand is fixed for an extended period and all generators except the marginal generator maintains a constant bid price. If, under this set of conditions, the marginal generator were to lower its bid price by 50% (say), then it would be located lower in the price stack and consequently be dispatch to 100% of its capacity. A new marginal generator would appear at a lower bid price (and hence lower pool clearing price). The impact of this behavior by the marginal generator is to increase its production at a lower pool clearing price. The payoff for the original marginal generator is now given by:

$$\text{payoff} = [Q_c \times (P_c - P_p)] + [V_c \times (P_c - P_v)]$$

and since $P_p < P_v$, the expression can be rewritten as:

$$\text{payoff} = [Q_c \times (P_c - P_p)] - [V_c \times (P_v - P_p)].$$

That is, the marginal generator has reduced its short term payoff from the original position and has further forced the pool clearing price to fall. The lower pool clearing price will be factored into the forecast pool price by the multiple buyers, and when the marginal generator attempts to

Figure A.2
Bid price stack for an energy pool

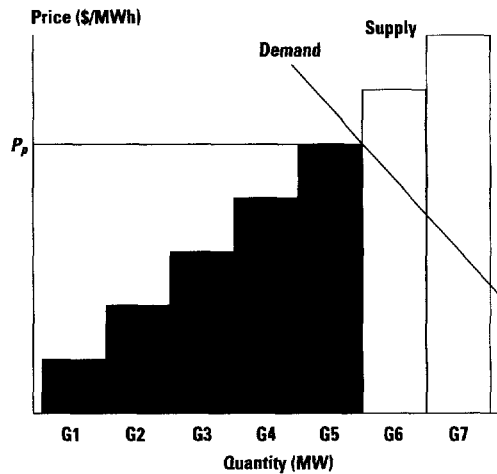
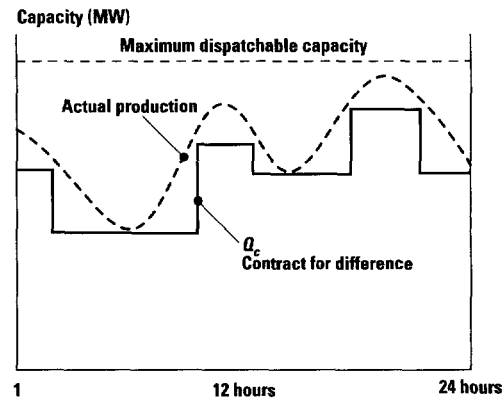


Figure A.3
Power plant daily contract for differences profile



negotiate a new CfD contract, it will be faced with buyers who collectively expect to pay a lower contract price. This will reduce the marginal generator’s long term payoff.

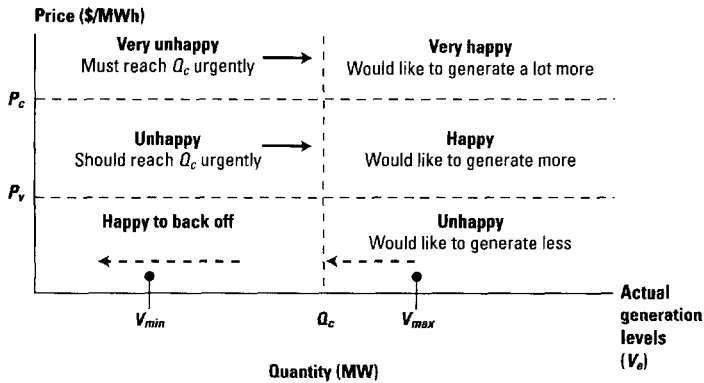
It is evident from this example that each generator will maximize its long term payoff by bidding at its marginal cost.

Incentives Provided by a Contract for Differences

When the pool price drops below the cost of production ($P_p < P_v$), the generator reduces its output

Figure A.4

Incentives provided by a contract for differences



(figure A4). When the pool price rises above the cost of production ($P_p < P_v$), the generator increases its output. Between the prices P_p and P_c the generator is encouraged to increase output up to and beyond some target (such as Q_c).

When the pool price moves above P_c , the generator is encouraged to urgently increase output to Q in order to avoid incurring a financial penalty. A generator that increases output beyond Q_c can earn substantial additional revenue.

All these incentives occur as a result of a single common clearing price in each trading period. The publication of the price to all parties provides incentives to improve generating plant performance, reduce the cost of delivery, and encourage efficient investment.

Glossary

administrative valuation. Determination of the value of an asset such as a generation plant or station based on criteria and guidelines established by the government or regulator. This valuation is undertaken as a substitute for determining the value through the competitive auction-based sale of the asset. *See also* **market valuation.**

ancillary services. Services that must be provided in the generation and delivery of electricity to ensure the reliable operation of integrated transmission and generation networks. Examples include loss compensation, automated generation control (load frequency control), coordination and scheduling services (load following, control of transmission congestion), and support of system integrity and security (reactive power, spinning and operating reserves).

bilateral transaction. Direct transaction entered into by two market participants and defined in a contract between the participants.

captive consumer. Electricity user who has no choice of electricity supply but must purchase electricity from the distribution utility serving the franchise area.

clawback. Adjustment generally made by a regulator to recover from an electricity producer profits that exceed the expectations of a contract or agreement.

competitive transition charge (or compensation). Charge that cannot be bypassed and that is levied on all customers of a distribution utility, including those who purchase directly under contracts. The charge is used to recover funds to compensate for the stranded costs that arise from the transition to a competitive power market.

competitive pool market. Market arrangement in which all individual unbundled generators bid output into a single spot market to compete for dispatch. The price in the energy pool is determined by supply and demand.

congestion. Result of constraints on the transmission network restricting the purchase and sales transactions that market participants may wish to implement.

congestion management. Attempt to relieve transmission congestion by adding transmission capacity, implementing congestion pricing, modifying the economic merit order, or other means.

congestion pricing. Settlement process used to account for the energy cost implications of system congestion. Generally, higher-priced generation in one area will displace lower-priced generation in another to relieve congestion while satisfying demand.

contract for differences (CfD). Bilateral financial instrument between a seller (generator) and a

buyer (distributor, marketer, or qualified user) of electricity that protects both parties against price volatility. If the pool-clearing price is below the contract price, the purchaser pays the difference to the generator; if the pool-clearing price is above the contract price, the generator pays the difference to the purchaser. *See also vesting or transition contract for differences.*

cross-ownership. Asset ownership situation in which an entity operating in a competitive (or potentially competitive) segment of the industry, such as generation and distribution, also has an ownership interest in the monopoly segment of the industry, such as transmission. This is discouraged because it could lead to an unfair advantage to the generator or distributor with cross-ownership in transmission.

demand-side management. Planning, implementation, and monitoring of activities by electricity companies to encourage consumers to modify their patterns of electricity usage by changing the level or timing of consumption.

economic dispatch, economic merit order. Loading generating units with the lowest incremental costs first.

eligible consumer. An electricity user who has the right to choose and contract directly for supplies with generators or wholesalers, and thereby bypass the local distribution utility.

embedded generation. Generating capacity in an electricity supply entity that is not primarily a generator, such as a generating unit owned by the provincial supply bureau, which primarily distributes electricity.

energy broker. Market intermediation or market-making mechanism for arranging hourly nonfirm bilateral energy transactions. The energy broker may post buy and sell bids on an electronic bulletin board, allowing market participants to choose which bids to accept and to execute transactions directly with the counterparty. Alternatively, the energy broker may facilitate the transactions by matching buy and sell bids. *See also nonfirm power.*

energy pool. Mechanism in which individual unbundled generators bid output into a single spot market to compete for dispatch. The price in the energy pool is determined by supply and demand.

extent of use pricing. Transmission pricing method in which transmission system costs are allocated in proportion to each user's average use of each transmission line.

franchise area. Defined geographic area in which a distribution utility is assigned the obligation to provide electricity supply to all consumers who request service.

grid code. Set of rules, guidelines, and standards that govern the connection to—and operation of—a transmission network. Participants on the interconnected transmission network must follow the metering, technical connection requirements, and normal and emergency operating protocols defined in the grid code.

Herfindahl-Hirshman index (HHI). Popular measure of industry concentration that combines elements of the number of firms in the industry and inequality among them. The HHI is the sum of the squares of the market share of each firm in the industry. When an industry is occupied by only one firm—a pure monopolist—the index attains its maximum value of 1.0 (or 10,000 when the market shares are measured in percentage terms). The value declines with increases in the number of firms and increases with rising inequality among a given number of firms.

independent power producer. Independent enterprise that owns, operates, and maintains a generating plant but does not usually operate the transmission or distribution system to which the plant is connected.

independent system operator (ISO). Neutral operator responsible for maintaining an instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of generation plants to ensure that loads match resources available on the system.

Lerner index. Measure of monopoly power in an industry that directly reflects the inefficient departure of price from marginal cost associated with monopoly.

$$\text{Lerner index} = (\text{price} - \text{marginal cost})/\text{price}$$

Under pure competition the Lerner index is equal to zero. The more pricing departs from the competitive norm, the higher is the associated Lerner index value.

load following. Ability of an electric system to regulate its generation to follow minute-to-minute changes in customers' demand. Also, a generation plant that automatically acts to balance the system.

locational pricing. Pricing that reflects the location of generating facilities and the limits of the transmission network. Good locational pricing reduces congestion and inefficiency by providing the proper incentives for economic dispatch and planning of generation and transmission.

mandatory energy pool. Electricity pool in which all generators are mandated to participate in order to sell their electricity to consumers.

market clearing price. Price at which supply equals demand in the power market, usually equal to the bid price of the marginal generator dispatched to meet energy demand.

market code. Framework of rules established and administered by the market operator that governs bidding, balancing supply and demand, market participation, and settlement calculation.

market operator. Entity that sets and administers the market code. The market operator receives bids, schedules generation in a power pool-type market, performs settlement, and may operate as an energy broker. Unlike the purchasing agent in the single buyer model, the market operator does not own the power it purchases.

market power. Ability of a generation firm in a competitive power market to raise its price above the marginal cost of production and maintain it at that level for a appreciable period. This is gen-

erally perceived as an unfair advantage over other market participants.

market valuation. Asset value determined through a competitive auction in the open market.

merit order bid stack. Ranking of generation plants by their bid prices—from lowest to highest—to determine their production and dispatch schedules to meet demand.

“new plant, new price” policy. Government of China policy introduced in 1985 that allowed all plants built after 1985 to obtain a tariff permitting rapid recovery of capital costs.

nodal pricing. Pricing energy by location (node) to reflect the costs of transmission congestion.

nonfirm power. Power or power-producing capacity supplied or available under a commitment with no assured availability or limited assured availability.

nonspinning reserve. Portion of off-line generating capacity that can be synchronized and ramped to a specified load in 10 minutes and run at least 2 hours.

operating reserve. Reserve generating capacity, both spinning and nonspinning, needed to allow an electric system to provide load following and frequency regulation, as well as to recover from generation failures.

passive ownership. Ownership role, generally based on a minority equity stake, played by an equity owner that does not play a role in establishing or influencing corporate and operational policies and practice in the entity.

peaking capacity. Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may operate at certain times as peaking capacity and at other times to serve loads around the clock.

pool-clearing price. Market or bid price at which supply meets system demand in the power pool.

postage stamp rates. Transmission tariffs that are uniform within a jurisdiction.

potential market power. Tacit market power. An entity may have this power but choose not to exercise it. *See* **market power**.

power purchase agreement. Long-term contract in which a generator sells electricity to a provincial power company.

provincial supply bureau. Distributor for a provincial power company. As part of reform in China, these bureaus will be spun off as independent entities and permitted to purchase electricity directly from generators in the spot market or through bilateral contracts.

purchasing agent. Entity responsible for aggregating the demands of small consumers and for purchasing energy from generators through contracts or from the competitive energy pool.

reactive power. Electricity that establishes and sustains the electrical and magnetic fields of alternating current equipment. Reactive power must be supplied to most kinds of magnetic equipment and to the reactive losses on transmission facilities. Provided by generators, synchronous condensers, and electrostatic equipment, such as capacitors, reactive power affects system voltage.

reserve margin. Percentage of generating capacity need above the expected maximum demand.

settlement. Accounting and billing to determine the amounts market participants pay or receive for their energy transactions.

spinning reserve. Portion of unloaded synchronized generating capacity that can be loaded in 10 minutes and run at least 2 hours.

spot energy transaction. Transaction between a buyer and seller for immediate delivery of a defined amount of energy.

spot market. Market in which electricity can be purchased for immediate delivery, with coordination of bids and settlement of transactions handled by the market operator.

stranded costs. Prudent costs incurred by a utility that may not be recoverable under market competition. Examples are deferred costs, long-term contract costs, and undepreciated generating facilities.

strike price. Predefined level of market price, which if exceeded would require the seller to compensate the buyer for the difference between the actual market price and strike price.

system operator. Entity responsible for generation and interchange dispatch, system reliability and security, and transmission switching. Unlike the market operator, which balances financial supply and demand ahead of time, the system operator matches physical supply and demand in real time.

vesting or transition contract for differences. Financial contract negotiated between generators and purchasers that guarantees the financial positions of each entity during the initial period of operation.

wheeling. Movement of electricity from one system to another over transmission facilities of intervening systems.

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