REPORT

WHOLESALE ELECTRICITY MARKET DESIGN

Rationale and Choices

ESMAP
Energy Sector Management Assistance Program

THE WORLD BANK
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ABOUT ESMAP

The Energy Sector Management Assistance Program (ESMAP) is a partnership between the World Bank and 24 partners to help low- and middle-income countries reduce poverty and boost growth through sustainable energy solutions. ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank Group (WBG), ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7) to ensure access to affordable, reliable, sustainable, and modern energy for all. It helps to shape WBG strategies and programs to achieve the WBG Climate Change Action Plan targets. Learn more at: https://esmap.org.

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Contents

Key Findings vi

Acknowledgements viii

Abbreviations ix

Executive Summary x

1. The Evolution and Current State of Power Markets xii

2. Why Market Reform? 8
- Evidence on the Performance of Systems with Competition in the Market 9
- Preconditions of Successful Market Reform 10

3. Key Elements of Market Structure 14
- Creating a Competitive Playing Field: Unbundling 15
- Legacy Issues 17
  - Stranded Costs 17
  - Legacy Contracts 18
- Natural Monopoly Segments within Integrated Systems 20
- Open Access 21
- System Planning in Market Systems 21
- Governance Arrangements 23
  - Overview of Governance Issues 23
  - Design Options for Implementing Agencies 26

4. Electricity Market Design 28
- Operations 30
  - Optimal Dispatch in the Real-Time Spot Market 30
  - Types of Markets 30
  - Price Formation in Markets 33
  - Sequence of Markets and Intertemporal Hedging 35
  - Imbalance Settlement and Forward Markets 36
  - Congestion Management and Pricing 38
- Investment 39
  - Energy-Only Markets 41
  - Capacity Markets 43
  - Mandatory, Long-Term Contracts 44

Ancillary Services 45
Regulation and Contingency Reserves 46
System Stability 46
Procurement of Ancillary Services and Co-Optimization 47
Remedies for the Abuse of Market Power 47
Markets, Climate Change, and Energy Transformation 48
Controlling Emissions and Carbon Pricing 49
Variable Renewable Energy and Battery Energy Storage 50
Distributed Energy Resources: Distributed Generation 52
Distributed Energy Resources: Demand Response 53

5. Undertaking Reform 54

Reform Process: Market Objectives and Country Context 55
Reform Process: Checklist for Implementation 57
Step 1. Assessment of Prerequisites for Reform 57
Step 2. Choice of Market Design 58
Step 3. Market Commencement 60

Endnotes 62

Glossary 67

Bibliography 71

List of Figures, Tables and Boxes

List of Figures

Figure 1.1: Percentage of Developing Countries Adopting Some Degree of Unbundling over Time 5
Figure 1.2: Introduction of Wholesale Electricity Markets 5
Figure 1.3: Status of Electricity Markets in 2020 6
Figure 3.1: An Example of a Power Sector Structure Allowing Open Access 22
Figure 4.1: Demand-Supply Curve for the Indian Energy Exchange 33
Figure 4.2: Electricity Market Timeline 35
Figure 4.3: Cumulative Storage Deployment by Country, Projections 2018–30 51

List of Tables

Table 2.1: Overview of Preconditions among Group of Countries at the Time of a Reform 11

List of Boxes

Box 1.1: Market Reform in Peru and Colombia 4
Box 3.1: Vietnam's Power Sector Reform 16
Box 3.2: Independent Power Producers 19
Box 3.3: Establishment of Turkey's Energy Regulator 25
Box 4.1: Fulfilling Long-Term Contracts in Markets in Gross and Net Pools 37
Box 4.2: Taking Measures to Prevent Withholding of Capacity 42

Key Findings

While there is now an abundance of research and a first crop of textbooks on the topicof competition in electricity markets and their design, the literature tailored to developing countries is surprisingly thin. Extensive research on markets in developed countries can assist in the design of markets elsewhere, but do not provide ready-made plans. Intelligent market design needs to consider the state of development, including potentially different policy objectives and the institutional capacity of developing countries.

To fill this gap, the 2019 World Bank report, *Rethinking Power Sector Reform in the Developing World,* took stock of the nature and pace of power sector reforms enacted in the developing world. Its comprehensive, historical perspective highlighted preconditions for the introduction of a market. Further, an upcoming report from the International Finance Corporation, "Creating Markets: Power Markets for Development," classifies power systems and markets in 230 countries and territories and highlights some of their design features.

Both works are valuable, citing recent sources of information about electricity markets. A primer that unites the concepts underlying the design of any electricity market with design considerations that consider the contexts of developing economies, including location-specific issues, pitfalls to avoid, and global lessons learned, would be a useful complement. The present primer is intended as such a primer. It does not provide predefined "best solutions," but instead lays out key design principles and market design challenges. Reflecting the current state of the art, the primer aims to support policymakers contemplating market reform, as well as their advisors, by presenting debates about market design in nontechnical terms.

This primer distills key points from textbooks and the broader academic/industry literature. It extrapolates the core issues and concepts that typically fill a 400-page textbook or several thousand pages of technical research papers into a succinct, 60 pages of nontechnical descriptions useful for World Bank staff, consultants, and stakeholder organizations in partner countries.

Unbundling vertically integrated monopolies is well understood, but just the beginning of reform. Electricity markets do not respond well to laissez-faire approaches. They require market design, carefully crafted for each system to meet specific policy objectives that often go beyond cost reduction through competition. This primer walks readers through the complex maze of benefits, issues, and trade-offs. As it presents design options, it helps readers to frame the right questions in order to explore these options in greater depth.

The designs of electricity markets are still evolving. Barely three decades ago, it became feasible to introduce advanced, bid-based electricity markets compatible with the physical operation of a power system. Globally, 56 countries now feature power systems with competitive, cost– or bid–based wholesale markets. These include most countries in the Americas, Europe, and Oceania (except for small island economies), as well as a growing number of countries in Asia: India, Japan, the Philippines, Singapore, and the Republic of Korea. China is experimenting with competitive, wholesale markets in several provinces. Yet, only one in five developing countries has introduced a wholesale market during the past 25 years. Several other developing countries are exploring whether and how to move to wholesale electricity markets.

As new technologies are introduced both on the supply (e.g., renewable energy, battery storage) and demand (e.g., electric vehicles, distributed generation, demand response) sides, greater market design challenges are posed to many client countries, whether they have a working market or are considering establishing one.

Amid growing appreciation of the constraints of relatively small, developing systems, interest is rising in regional electricity markets and regional power pools, with examples offered by advanced regional markets such as the Southern African Power Pool (SAPP) and Central American Electrical Interconnection System (SIEPAC). Regional markets connect electricity systems across national borders to enable electricity trade and the sharing of reserves, allowing smoother integration of larger shares of variable renewable energy sources and quicker adoption of new technologies.

This primer will be followed by a series of knowledge notes that delve deeper into more specific technical issues of interest to World Bank staff and stakeholders in client countries including regulators, system operators, ministries, and utilities. The specific topics of these papers will be selected based on feedback from World Bank staff and client organizations, but they are expected to cover the role of markets in the transition toward decarbonized and green systems of the future, and to include good practice notes on facilitating new technologies and enabling flexible electricity grids through new market instruments, transmission interconnectivity, regional trade and markets, and legacy and contractual solutions.

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Abbreviations

AC	alternating current
BES	battery energy storage
CfD	Contracts for Difference
COMELEC	Comité Maghrébin de l'Electricité
DC	direct current
DER	distributed energy resources
DPO	Development Policy Operations
EEX	European Energy Exchange
EML	Electricity Market Law
EMRA	Energy Market Regulatory Authority
GWh	gigawatt-hour
ERC	Energy Regulatory Commission
FTR	financial transmission rights
IPP	independent power producers
kWh	kilowatt-hour
MWh	megawatt-hour
ISOs	independent system operators
LCOE	levelized cost of electricity
O&M	operation and maintenance
OTC	over the counter
PPA	power purchase agreements
PURPA	Public Utility Regulatory Policies Act
RGGI	Regional Greenhouse Gas Initiative
SAPP	Southern African Power Pool
SIEPAC	Central American Electrical Interconnection System
SO	system operator
SOE	state-owned entity
T&D	transmission and distribution
VRE	variable renewable energy
WAPP	West African Power Pool
WPT	willingness to pay

All currency is in United States dollars (US$, USD), unless otherwise indicated.

Executive Summary

Barely three decades ago, it became feasible to introduce advanced, bid-based electricity markets compatible with the physical operation of a power system. Today, around 60 countries have power systems with competitive cost- or bid-based wholesale markets. These include most countries in the Americas, Europe, and Oceania (except small island economies), as well as a growing number of countries in Asia including India, Japan, the Philippines, Singapore, and South Korea. China is experimenting with competitive wholesale markets in several provinces. Several other developing countries are exploring whether and how to move to wholesale markets in their power systems.

Interest in creating electricity markets also arises from the examples offered by power pools that interconnect electricity systems across borders to enable electricity trade and the sharing of reserves, including several relatively advanced regional markets like the Southern African Power Pool (SAPP) and Central American Electrical Interconnection System (SIEPAC).

It has become common to classify the structure of electricity systems based on the extent and type of competition that they feature (See, for example, Hunt 2002):

- Vertically integrated monopoly: Systems run by a single monopoly.
- Single buyer: Systems whereby monopolistic companies carrying out transmission and distribution (and often some generation) buy some or all electricity from generators. This is competitively procured under long-term power purchase agreements (PPA), a form of competition “for the market.”
- “Wholesale and retail competition: Systems whereby “merchant” generators compete with one another on an ongoing basis (head-to-head) for sales to distribution companies and other users, a form of competition “in the market.” Under wholesale competition, only large customers buy from the market. Under retail competition, all customers have a choice of retailers or suppliers to buy from. Retailers, in turn, aggregate the demand of their customers and buy “in bulk” at the wholesale level.[i]

This primer focuses on competition in the market: the creation of competitive markets for electricity generation. As such, it summarizes a number of well-understood sector reforms needed to embed competitive markets in electricity systems. It then explains that putting the players in place, by unbundling monopolies for example, is just the beginning of reform. Laissez-fair approaches do not work for electricity markets. They require market design, carefully crafted for each system to meet a wide range of objectives that go beyond cost reduction.

This primer suggests ways to think about designing competitive electricity markets. It does not provide “recipes,” but lays out design principles and several key market design debates.

The primer is meant to be a primer of sorts, supporting policymakers contemplating market reform, as well as their advisors, by presenting the debates about market design in nontechnical language.

The primer starts with a brief overview of the evolution of competitive power markets and the current global landscape of electricity markets. It further reviews the arguments for markets, including existing evidence as well as basic preconditions for market reform. The main body of the report then walks through key market structuring and design issues, including considerations to address decarbonization objectives. Topics addressed include the promises and challenges posed by the integration of variable renewable energy and new technological solutions such as battery energy storage (BES) and distributed energy resources (DER). The report concludes with a brief characterization of key market design choices and a generic list of process steps required for market reform.

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ONE

THE EVOLUTION AND CURRENT STATE OF POWER MARKETS

Electric power systems emerged in the second half of the 19th century and were typically owned by private investors, where generation had to be close to the location of consumption (Klein and Roger 1994). Different uses of electricity (e.g., streetcars or lighting) required different voltages and separate lines. The market structure was composed of distributed generation and mini grids, mainly using direct current (DC).

Integrated, state-owned monopoly companies became the organization of choice by the mid-20th century. Alternating current (AC) made long-distance transport (high-voltage transmission) advantageous, allowing economies of scale for generation plants and trade among deficit and surplus areas. Larger systems were developed at the municipal, regional, and national levels. The monopolies performed all functions, including generation, transmission, and distribution.

Power monopolies underpinned the unprecedented economic growth of the second half of the 20th century, although performance was uneven. In more advanced economies, monopoly utilities usually delivered power to citizens at a high cost due to the lack of incentives to operate and invest efficiently (Joskow and Schmalensee 1983). In developing economies, many power companies failed to provide access and quality of supply. They operated unreliably (Huenteler et al. 2017), primarily due to a lack of managerial accountability, outdated infrastructure, operational inefficiencies (poor collection rates and high rates of technical and commercial losses), and, most importantly, end-user tariffs being set below cost-recovery levels. Issues such as inefficient planning, operations, and investment plagued many monopolies (World Bank 1994). A recent review finds that in many cases, such problems persist, not least due to politicized governance (World Bank 2019).

Governments began to introduce competition in electricity systems due to various problems related to specific country contexts. These included: (1) inefficiencies in investment resulting in over- or undersupply; (2) high operating or investment costs; (3) poor billing and collection; (4) pressure on the fiscal system resulting in a drain on public finances; and (5) a need to attract private finance. Furthermore, the incumbent monopoly may not adopt improved technologies adequately, including those required to address greenhouse gas emissions.

Market-oriented reform sought to address multiple problems in the electricity system. In principle, an efficient electricity market can deliver the same or better quality and reliability of supply as a highly commercialized, state-owned enterprise (SOE), but with less commitment of public funds. If properly regulated and incentivized, private market participants may be stricter in allocating capital, managing construction costs, and coordinating operation and maintenance (O&M) costs over the lifecycle of an asset than the public sector. Private market participants might also be better able to manage risks or push back against political pressures than a SOE with weak governance. Relevant reform efforts can also facilitate a systematic analysis of problems and force policymakers to confront core issues.

The search for competitive markets may motivate reform and force policymakers to address basic problems. Yet, markets per se will not miraculously create payment discipline or attract more financing. So, what can one expect from the introduction of wholesale competition? What can competition achieve that monopolies cannot, even when equipped with state-of-the-art optimization models to guide operation and investment decisions?

Departments in regulated or state-run monopolies may have weak incentives to perform or to reduce costs.[1]

Relevant information may be hidden or unavailable. For example, monopolies all too often lack basic information about their cost structure, needed to make efficient decisions. Costly legacy plants may have strong, in-house support in the face of new, more efficient options. Furthermore, regulating monopolies requires an established and strong regulatory capacity that may not exist.

Introducing wholesale competition thus holds three main promises. It can:

- Provide greater incentives for generators and suppliers to perform (e.g., to be available for dispatch or cut costs)
- Provide greater incentives to reveal information about the best operating and investment options, ensuring greater transparency of the overall sector
- Facilitate entry of new, more efficient plants and market participants-

Creating electricity markets can be seen as complex. Arguably it is, however, no more complex than running an electricity system as efficiently as possible under monopoly provision. In a sense, modern electricity markets take insights into the efficient pricing of electricity seriously by providing better incentives to operate and invest efficiently.

Market reforms originated in the 1970s and 1980s, when policy and intellectual ferment paved the way for the introduction of market forces in electricity systems. In the United States, the 1973 oil crisis set legislative efforts in motion, culminating in the 1978 Public Utility Regulatory Policies Act (PURPA). The legislation was intended to reduce dependence on oil and gas. One of its major effects was that electric utilities were obliged to purchase power from independent power producers (IPPs) that could generate electricity for less than the alternative cost of the utility's traditional generation source: its "avoided cost" or opportunity cost. The result: during the 1980s, a wave of long-term power purchase agreements (PPAs) enabled IPPs to compete for the right to deliver to monopoly utilities—a form of competition for the market in the generation segment.[2]

Market reforms in developing countries started in Chile. The country introduced competition in the market for power in the late 1970s, motivated by the need to restore financial capabilities and reduce concentration and vertical integration in the sector, dominated by the Spanish Endesa. Generation, transmission, and distribution were unbundled. Transmission system ownership was diversified, and generators were afforded nondiscriminatory access to the transmission system. Deregulated consumers (large users with demand greater than 1 megawatt [MW]), could negotiate contracts freely with generators or distribution companies, while regulated consumers continued to be served by distribution companies. Pass–through to final users had an administratively set ceiling (node price) as incentive for efficiency in contracting decisions. In 1982, the new market started to operate. Contractual coverage of demand was mandatory, and the spot market was basically a forum to allow settlements among generators.

Experiments with new electricity markets continued in Peru, Colombia, Argentina, and Brazil in the 1990s. Box 1.1 shows a brief description of the market reforms in Peru and Colombia. Market reforms also advanced in developed countries, including Australia, New Zealand, Singapore, and several other European countries.[3]

In 2000–01, the California energy crisis triggered by drought and gas supply constraints revealed some of the challenges of market reforms. The wholesale market prices spiked, and generating companies were accused of withholding capacity to exercise market power. Utilities went bankrupt. When the dust settled, it became clear that basic design mistakes had been made. Notably, utilities buying in the wholesale market could not pass on scarcity prices to consumers due to a low price cap for final customers, and market participants were not allowed to hedge their exposure—hence the bankruptcies. The system was reregulated (Hunt 2002), and the enthusiasm for markets waned in the aftermath of the collapse of California's electricity market. If the best and the brightest in one of the world's most advanced economies could not make electricity markets work, then why even try? Countries such as Korea, Malaysia, and Thailand suspended their reform efforts.

As technological developments facilitated the introduction of more efficient market instruments, and markets delivered long-anticipated efficiency gains in developed systems, reform efforts once again gathered steam. California resumed its market reform. Countries all over Europe and in parts of Asia proceeded with procompetitive policy reforms. For example, the Philippines established a full-fledged power market with the spot market operating by 2006 (Rudnick and Velásquez 2019a). India set up two power exchanges for short-term contracts in 2008, including a day-ahead market and, most recently, a real-time spot market in 2020 (Tawde 2020). China established a broad policy direction toward competitive markets in 2015, with experiments in several provinces (Pollitt 2020). Kazakhstan introduced a capacity market in 2019, complementing the existing energy spot market.

The African continent stands out from the rest of the world in its struggle to develop power markets, with no single country fully implementing a wholesale power market and only two countries (Nigeria and Uganda) following around 80 percent of the prescribed "model" (Foster and Rana 2019). Several regions started practically experimenting with regional electricity markets: the Southern African Power Pool countries have had an operational, day-ahead market since 2015, an intraday market since 2017, and are currently introducing a balancing market.

Overall, upper-middle-income countries and those with large installed generation capacity (above 5 gigawatts [GW]) were much more likely to have implemented at least partial vertical unbundling than low-income countries. Currently, many developing countries have unbundled their power sectors to some degree, as shown in figure 1.1.

The introduction of market mechanisms has changed the landscape of electricity systems across the world, and a range of structures have evolved in different countries. In 1990, most electricity systems were organized as state-owned, vertically integrated monopolies; by 2020 the picture had changed fundamentally. Figure 1.2 summarizes the introduction of wholesale electricity markets over the years.

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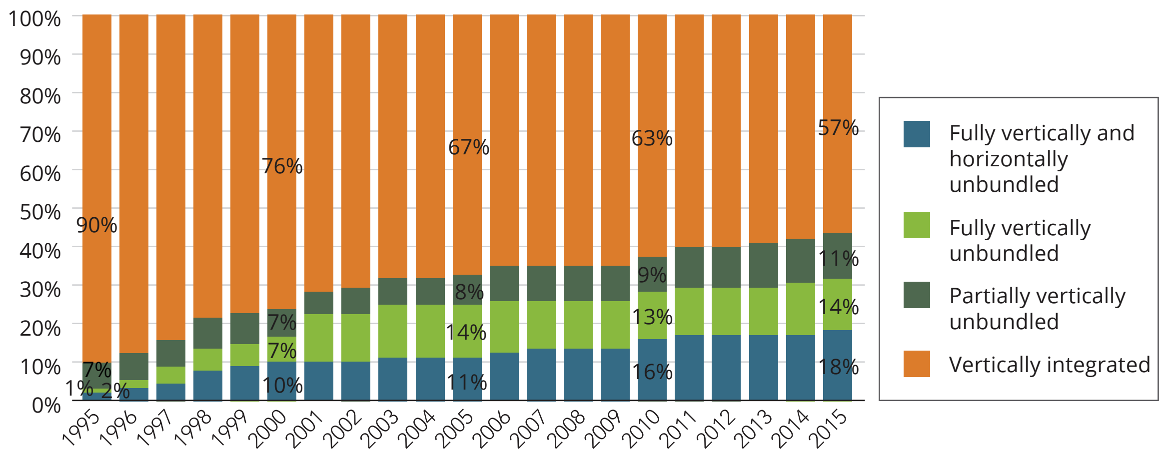
MARKET REFORM IN PERU AND COLOMBIA

The Peruvian power market was established in 1992, and has been continuously adapted to fulfill different government objectives. The Peruvian government improved the security of the power supply by diversifying power production away from hydropower toward gas-fired generation (Rudnick and Velásquez 2019c). The power market is composed mainly of bilateral contracts and a spot, cost-based power pool. Market concentration has fallen steadily due to increased competition. Rapid capacity additions and sluggish demand growth over recent years have contributed to depressed wholesale and contract prices. More recently, the country pushed for investment in renewable energies through competitive auctions, achieving modest but increasing levels of renewable generation. Moving forward, as identified by Wolak (2021a), there is a significant need to enhance the regulatory oversight of Peru's electricity supply. Establishing a stakeholder process for developing and adapting market rules, and establishing a formal market monitoring process, will reduce the scope for costly political intervention in the market.

Meanwhile, the Colombian power market was established in 1995, driven by concerns about the reliability of supply in the country's largely hydropower-based domestic power system and to ensure supply during tight hydrological conditions affected by the El Niño phenomenon (Rudnick and Velásquez 2019b). Despite initial enthusiasm, the market had difficulty delivering intended outcomes due to design and institutional issues, and multiple structural weaknesses. The government has intervened in the market during critical situations, and concerns persist regarding the exercise of market power, a steady increase of contract prices, and dysfunctionalities in reliability charges.

FIGURE 1.1

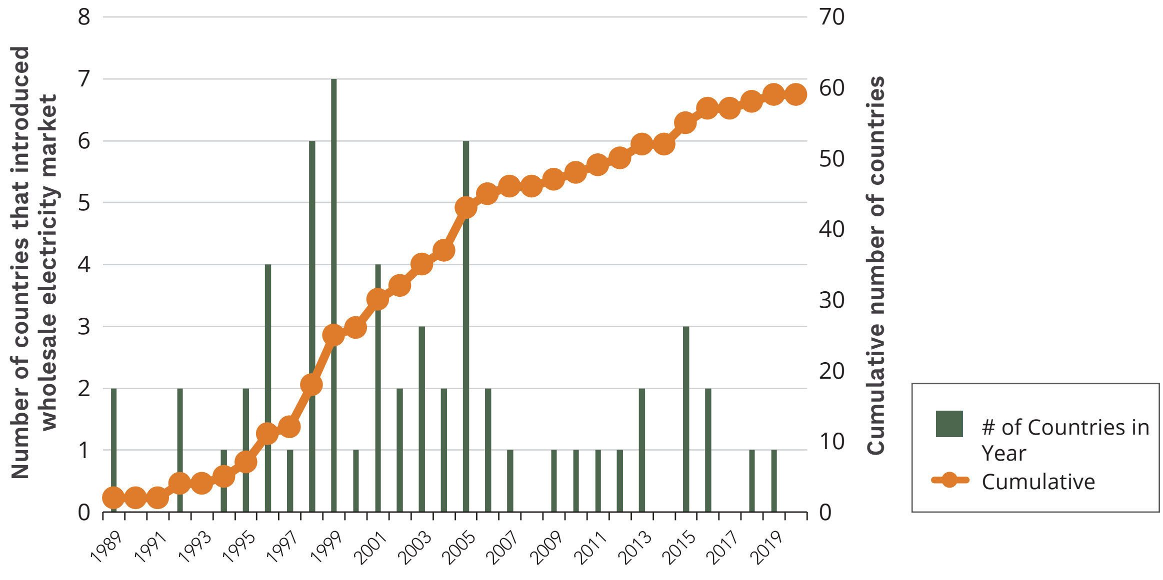
Percentage of Developing Countries Adopting Some Degree of Unbundling Over Time



Source: Foster et al. 2017.

FIGURE 1.2

Introduction of Wholesale Electricity Markets



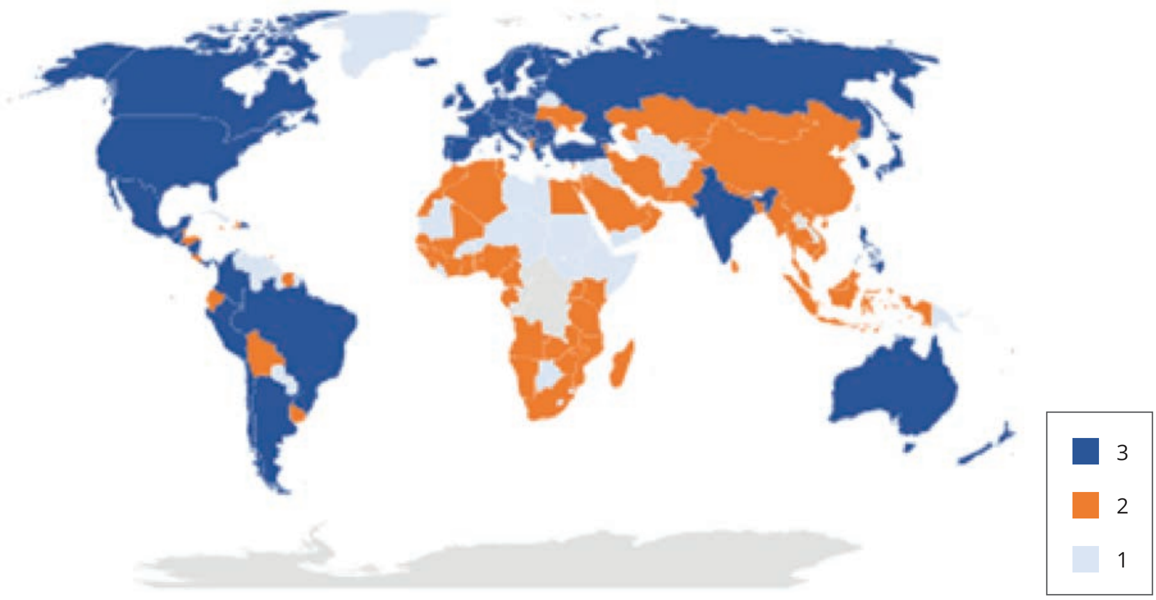
Source: Akcura and Mutambatsere. Global Market Structure Database. IFC. Forthcoming.

Based on International Finance Corporation (IFC 2020) data, vertically integrated monopolies are mostly found in low-income developing countries or small economies (see figure 1.3). State ownership in such monopolies is found in 81 countries and territories, most of them small island economies, several countries in Sub-Saharan Africa, plus a few others. Private monopolies operate in 18 economies. In 75 countries, the monopoly utilities entertain a degree of competition for the market by buying energy from private generators under long-term PPAs (in a single-buyer model). Such systems account for the rest of Sub-Saharan Africa and the Middle East, some island economies, and much of Asia. Some form of competition in the market is found in 56 countries: most of the Americas, Europe, Australia, New Zealand, and a few Asian countries such as India, Japan, the Philippines, Singapore, and Korea.[4]

It should be noted that the formal system structures laid out above do not tell the whole story about how electricity provision functions in poorer countries and fragile states.[5] There may be significant alternative sources of power outside the official system. For instance:

- In many systems, customers—whether they be large firms or households—may have the option to possess their own standby generation equipment. In systems that fail to connect many customers or are plagued by service interruption (load shedding) or full blackouts and possibly excessive voltage and frequency fluctuations, standby generation may be the most important source of power. In Nigeria, for example, it is estimated

FIGURE 1.3
Status of Global Electricity Markets in 2020



Note: 1 = vertically integrated monopolies; 2 = single-buyer market models; 3 = wholesale markets.

Source: Akcura and Mutambatsere. Global Market Structure Database. IFC. Forthcoming.

that private, captive generation capacity of 14–20 GW serves some 100 million people, significantly exceeding the official capacity of the system (12.5 GW), of which more than half is usually not available (Ferrero 2018). In India, captive power generation of some 78 GW accounts for a sizeable chunk of generation capacity, significantly exceeding the 5–6 GW typically traded in the country's wholesale markets.

- Some low- and middle-income countries—often fragile states—have off-grid electricity systems that supply groups of households, entire villages, or parts of towns. One study (Kariuki and Schwartz 2005) found that in the early 2000s, about 7,000 small electricity systems existed in 32 countries. This is likely to be an underestimate of the total (Kariuki and Schwartz 2005). In recent years, more countries have allowed off-system mini grids to develop, usually in areas that the main grid has not yet reached. The interest in renewable energy has in part underpinned such policies.

Considering these realities, many countries that have held on to vertically integrated monopolies have laissez-faire systems, relying on market forces outside official integrated AC transmission systems.

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TWO
WHY MARKET REFORM?

Evidence on the Performance of Systems with Competition in the Market

Competition in the electricity market was an entirely unproven concept just 40 years ago. Many argued that the lights would go out if one introduced competing players into electricity systems, which need to be run as one machine. The evidence now clearly shows that it is technically feasible to introduce a variety of forms of competition in generation. The larger economies have mostly embraced some type of competition in the market or are moving to do so. Market structure choices are well understood.

Empirical evidence shows that competition improves day-to-day operational efficiency. Kessides (2004) surveys evidence for emerging markets, including some spectacular improvements in Argentina after reforms in 1992, as the unavailability of power plants dropped overall from over 50 percent to 26 percent. For the United States, Bushnell and Wolfram (2005) as well as Mansur and White (2007) provide evidence that systematic efficiency improvements in operations clearly exceed implementation costs. The most robust benefit from competition appears to be reduced frequency and duration of outages, resulting in higher capacity utilization and higher total output per plant (Davis and Wolfram 2012, cited in IEA 2016). Markets have also facilitated the entry of more efficient plants in several regions, notably substituting gas for coal—as in the “dash for gas” that followed the introduction of competition in England and Wales. This becomes a useful feature as variable renewable energy (VRE) generation technologies gradually become more efficient.

Quality of service and access were improved, but with wide variation across countries. Jamasb et al. (2014) and Bacon (2018) surveyed the literature on power sector reform experiences across the world. They found no clear pattern of impact on prices, although efficiency and productivity increases were widespread, suggesting that overall net benefits from markets are positive. The surveys make it clear that policy approaches adjust to sector and country contexts, and it is hard to separate the effects of introducing competition in the market from other reform features such as ownership change or changes in provision of government subsidies.[6]

It is also clear that market systems can address policy concerns about access, affordability, and decarbonization with greater efficiency and more flexibility. On the balance, there is no argument that competition in the market is worse than monopoly provision. Clear gains are found in the operating performance of generators that exceed the costs of introducing markets. Competitive markets hold the promise of being much more flexible in enabling faster adoption of new technologies and business models than under the rule of monopolies, especially in countries with limited capacity to regulate. As intermittent renewables, batteries, and new types of demand (e.g., electric vehicles) reshape electricity systems, more complex incentive problems for generation and consumption need to be solved. Markets hold the promise to do this more effectively than regulatory intervention.

Preconditions of Successful Market Reform

While there is overall empirical evidence of the positive effects of competitive markets, specific results vary significantly among countries. Far-sighted governments are continuing to fine-tune market designs, deploying innovative solutions and preparing their systems for imminent energy sector transformation. While this experimentation is ongoing, the basic market design elements are clear. Substantial experience has been gained and lessons learned on how to avoid serious design mistakes (e.g., California in 2000–01). Many developing countries are still at the beginning of exploring the transition toward competitive markets, but reform processes can be politically challenging unless certain provisions that facilitate successful market reform are met. The World Bank's report "Rethinking Power Sector Reform" (Foster and Rana 2020) sets out four basic sets of conditions for the proper operation of any power system, but especially if competitive market reform is being contemplated:

- Adequate revenue is critical for operations and investment in any power system. That means tariffs and/or subsidies must cover all costs, and basic payment discipline with proper enforcement needs to be in place. When effective tariffs are adequate, the distribution segment of the system is solvent. Competition in power generation makes them comfortable that they will receive payment from distributors. Privatization of distribution can further help strengthen commitment to adequate, effective tariff levels.
- A sound contracting and regulatory environment (including enforcement and dispute resolution) supports the efficient operation of any power system. In systems with some form of unbundling, the formal contracting system is of particular relevance. Integrated monopolies in a market system need to have sound corporate governance mechanisms. All systems have elements that require price and quality regulation. Sound regulatory mechanisms are thus required whether they are part of the executive branch, managed by so-called independent regulatory agencies, or whether regulations are embedded in contracts with ultimate recourse through the court system.
- Broader country environment affects willingness and ability to invest and operate. At the extreme, a civil war is clearly detrimental to any type of power system. More generally unreliable property rights, for example, or erratic contract enforcement systems, hamper the ability to introduce competitive markets. Significant macroeconomic instability may also play havoc with any system.
- The introduction of market competition in power systems requires a minimum system size to allow a significant number of players for effective competition. As a rule of thumb, systems should feature at least 1 GW of capacity and at least four effective competitors of similar size and technology, unprotected by excessive transmission constraints.[7] This means market reform is most likely to be beneficial not only in large countries like China or India, but also in midsized systems or in regional power pools that manage electricity trade between countries.

Across developing economies, systematic differences can be observed in the uptake of reforms. Preconditions have played a role in shaping the outcome of reforms. Table 2.1 summarizes the preconditions in a sample of countries at the time of a reform (Foster and Rana 2020).

TABLE 2.1

Overview of Preconditions among Groups of Countries at the Time of a Reform

	SECTOR PRECONDITIONS						COUNTRY PRECONDITIONS	
	COST OF ELECTRICITY ($/kWh)	FULL COST RECOVERY (%)	SYSTEM LOSSES (%)	ACCESS TO ELECTRICITY (%)	ELECTRICITY CONSUMPTION (KWH pc pa)	SYSTEM SIZE (GW)	INCOME LEVEL (GDP pc)	QUALITY OF GOVERNANCE (INDEX)
Comprehensive reformers								
Stronger performers	0.15	69	19	82	1,413	20	1,405	–0.43
Weaker performers	0.17	70	30	53	315	15	756	–0.49
Limited reformers								
Stronger performers	0.13	55	21	77	804	22	731	–0.55
Weaker performers	0.23	84	27	27	172	2	428	–0.40

Note: GDP = gross domestic product; GW = gigawatt; kWh = kilowatt-hour; pc = per capita; pa = per annum

Source: Foster and Rana 2020.

All of these provisions matter. The first three sets of preconditions matter for improving the operations of any systems, be it integrated monopolies or competitive markets. The challenge is to assess whether a country is ready for market reform. The key is to judge—country by country—what is both technically sound and can be supported and sustained by the forces of politics.[8]

For example:

- Nigeria shows that unbundling generation, transmission, and distribution in a system larger than 1 GW need not work out any better than the integrated monopoly in the absence of government ability to sort out basic service delivery and payment discipline problems. The Nigerian experience illustrates the futility of unbundling in a sector without addressing other fundamental operating conditions. Huge technical and commercial losses (in excess of 50 percent of energy supplied) in electricity distribution have led to chronic payment problems along the electricity supply chain, and created a financial deficit in the order of US$1 billion annually. The resulting unwillingness of generators to produce electricity and gas suppliers to furnish fuel has led to crippling power outages, despite the fact that around half the country's generation capacity is paradoxically lying idle (Glachant, Joskow, and Pollitt 2021).
- Bolivia shows that basic markets may be possible at a smaller system size than 1,000 MW. A cost-based power pool was introduced in 1994 when the system size was only 400 MW.

The capacity of each generating company was not to exceed 25 percent of the total system capacity.

- India shows that power markets can develop in systems with significant payment problems and heterogeneous regulatory rules. The Electricity Act of 2003 paved the way for reform. Step by step, problems have been tackled, if not fully solved. Market-based trading mechanisms were introduced by power exchanges in 2008. The interest in improving trade among state electricity systems has evolved toward a more efficient, real-time balancing market, put in place in mid-2020.

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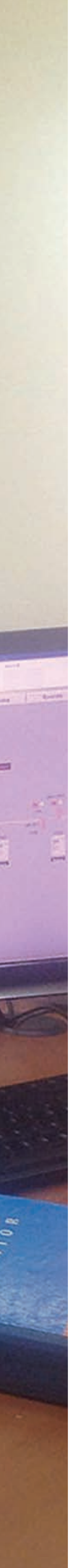
THREE
KEY ELEMENTS OF MARKET STRUCTURE



Modern, interconnected electricity systems allow competition in the market when fundamental public policies are in place. This includes an enabling market structure; regulation of system elements that remain natural monopolies (transmission, distribution, system operation); public planning mechanisms (e.g., for transmission system expansion); and governance mechanisms. This section discusses these elements in detail.

Creating a Competitive Playing Field: Unbundling

There are two key types of players in a competitive electricity market: generation plants and traders/suppliers. Generators own plants that produce electricity. Traders buy and sell electricity without necessarily owning plants.

A competitive market requires multiple generators, buyers, and traders that intermediate contracts. When generation companies control large market shares, “horizontal unbundling” may be necessary to create a critical mass of competitors and prevent reconcentration via mergers and acquisitions. For example, a country with five or six generation companies of even size is likely to experience stronger competitive pressure in generation than a country with one large and one small generation company only. Box 3.1 summarizes relevant aspects of Vietnam’s power sector reform.

While competition among generators and traders or suppliers is feasible, several natural monopoly segments will remain within an integrated electricity system, notably systems operation, transmission, and distribution. To minimize conflicts of interest, it is typically recommended that the different segments of a power system be “vertically” unbundled.[9] For example, a system operator owning generation may be able to discriminate against competing generators by delaying new generation interconnection studies, by not fully revealing information regarding available transmission capacity, and/ or by taking advantage of commercial information from third-party generators to ensure preferential treatment for the sale of its own power. Hence, the basic recommendation is to separate (vertically unbundle) the potentially competitive elements of the system (generation and trading/ selling of electricity) from the natural monopoly elements (transmission, distribution, and system operation).

Vertical unbundling is prevalent in most countries with matured markets (the US, Australia, most of Europe and Latin America), while very few developing countries have unbundled their utilities. Instead, they introduced independent power producers (IPPs), along with mostly vertically integrated utilities, which has led to creation of Single Buyer Models and “hybrid power markets” (Eberhard and Godinho 2017; Gratwick and Eberhard 2008; Vagliasindi and Besant-Jones 2013). While this model creates some space for IPPs to enter the market, it also introduces risks for future market development with rigid power dispatching based on inflexible take-or-pay arrangements with IPPs.

BOX 3.1

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VIETNAM'S POWER SECTOR REFORM

To improve the efficiency of the power and gas sector, the Government of Vietnam advanced reforms to introduce competition. Electricity liberalization started in 2004 with the unbundling of Electricity Vietnam (EVN), the establishment of a regulator, and the introduction of a competitive generation market to ensure the long-term sustainability of power supplies.

The World Bank supported power sector reforms in Vietnam through a series of three development policy operations (DPOs). One objective of the series was to increase the independence and diversity of electricity generators, creating conditions for effective competition. The target was to reduce the maximum proportion of generation owned by a single company from 70 percent to 45 percent. The DPO series, however, only achieved a modest reduction of 4 percentage points (from 70 percent down to 66 percent), reinforcing that reducing the ownership share of state-owned utilities is challenging. The DPO series did achieve other reform objectives, such as enhanced transparency in generation contracting and pricing and greater predictability for investors.

System operators that physically run the system day by day should be independent of other players to enable fair competition. That also goes for the market operators and settlement administrators providing the platform for trading.[10] Several power companies in the United States, for example, are not fully unbundled, hence particular importance is placed on creating independent system operators (ISOs).

Competition lowers costs and excludes technologies that are uneconomical. The key to competition in the market is openness to new generators with lower costs, while allowing underperforming generators to exit before the end of their operationally useful life or the term of the operating permit. A decision to exit is based on whether the market will provide revenues sufficient to meet the generators' operating costs going forward. A decision to enter is enabled by a transparent environment that allows any project or technology (generation, storage, or demand side) to demonstrate its value to the customer based on the combination of value, capital costs, and risks, which collectively determine whether a project will flourish or fail.

The ownership form of choice for system segments with competition in the market is private ownership. Competition may also involve state-owned companies but, in practice, state-owned companies may not truly compete with one another. Even if allowed, their incentive to perform is easily undermined by an implicit guarantee of their finances by the government: that is, the taxpayers. As a result, excessively costly state-owned generators may be invested in and operated. Most electricity systems with competition in the market feature private competitors, as do those still relying on the single-buyer model like Egypt and Thailand, or more competitive ones like those in Latin America, Turkey, or India.

Legacy Issues

Systems where private ownership of generation prevails before the introduction of competition may also complicate the transition to a market. Both horizontal and vertical unbundling may be hard as governments and regulators may be reluctant to interfere with the property rights of preexisting private players in the electricity system. Conflicts of interest then persist.[11] Important legacy issues to consider are stranded costs and legacy contracts.

Stranded Costs

A practical concern with introducing competitive market structures is the treatment of so-called stranded costs. The term "stranded costs" characterizes situations where investors are unable to recover all their fixed costs and have to write down equity or even enter into bankruptcy—that is, default on creditors. In competitive markets, the exit of underperforming firms is normal. Free market entry means little if inefficient firms are not allowed to fail. Investors taking losses does not mean firms close down. As long as revenues cover variable costs, firms should continue to operate. After all, their fixed costs have already been incurred. However, prior to the creation of electricity markets, the investments of generation companies might have been approved by regulators or set by contracts and their prices allowed to recover the approved costs, including a return on capital.

When the policy regime changes to a market, prices may drop due to greater incentives to operate efficiently. For example, nuclear or coal plants might be in trouble and incur stranded costs, meaning investors will no longer be able to earn their full, expected return on assets. If investors did not make allowance in their project evaluation for the risk of regime change and consequent losses, they may claim that the change in policy regime constitutes a form of expropriation because generators can no longer charge the regulated or contracted prices that they were promised.

While changing a policy is a legitimate function of government, investors may ask for compensation. Different jurisdictions treat the claim for compensation differently. It also matters, for example, whether firms should have foreseen the introduction of markets prior to their investment. More broadly, governments are typically allowed to interfere to some degree with the finances of private firms, for example via tax or other policy changes, without this resulting in valid claims for compensation. How a jurisdiction treats the issue may affect whether new investment will be forthcoming and at what cost. Sometimes the nature of contractual remuneration is explicitly provided for: for example, in contracts with IPPs. This is an issue affecting reform in countries all over the world including, for example, the Dominican Republic, the Philippines, and Turkey. “Legacy” investors may need to be compensated, or the old contractual arrangements “grandfathered” into the new system as vesting contracts.

Legacy Contracts

Depending on a country’s starting position, inefficient legacy payments may continue to be borne by customers, and contracts may not lead to fully efficient dispatch. Nevertheless, efficiency can be enhanced overall, as the old contracts would have been in force anyway and will eventually expire.

The challenge is to determine what market rules apply to generators with legacy contracts. Possible solutions depend on the particular design of the new power market. Basic options range from mandating generators fully participate in the market, to compensating them with a fixed payment. This might include, for example, a monthly amount over the life of the plant, or so-called vesting contracts—or contracts for differences, CfDs—which phase out the original contractual payments over time while exposing the generator more and more to market forces.

Power purchase agreements with IPPs may introduce rigidities by standing in the way of reform (refer to box 3.2). It may, for example, be costly for the IPP to fulfil its contract when the plant is not available for some reason. However, the introduction of competitive spot markets can make it easier for IPPs to fulfil their contract by making up shortfalls through spot market purchases. The flexibility offered by markets may facilitate agreements on ways to introduce competition.

BOX 3.2

INDEPENDENT POWER PRODUCERS

Contracts with independent power producers (IPP)* may help make companies or projects viable and help raise finance for new investments. For a project with ostensibly adequate tariff levels, governments in fiscal difficulty may be tempted to divert cash flow generated by the project to plug unrelated fiscal holes and thus reduce the company's ability to pay its financiers. Private property rights provide a shield against this temptation to some degree, as governments may be wary of interfering with private property rights for fear of killing off private investment more broadly (Klein 2015).

IPPs that combine investment and operation in generation have gained in popularity. Urpelainen and Yang (2017) demonstrate that providing the option for IPPs has raised investment in power generation in emerging markets. The World Bank (2019) found that a little over 40 percent of new generation has been procured as IPPs in developing economies. In low-income countries the share was just a bit below that of upper-middle-income countries. Close to three-quarters of intermittent renewable power plants have been procured as IPPs. Detailed cost-benefit analysis comparing the experience of IPPs to the performance of generation in monopoly systems hardly exists—not least because monopolies often do not have data that allow the performance of their generation assets to be isolated. For a relevant study, see Zhang (2018).

* IPPs are sometimes owned by governments from other jurisdictions. The key is whether the domestic or local taxpayer must provide some type of subsidy in case contracted services are not paid for as agreed.

Natural Monopoly Segments within Integrated Systems

The wire-based transmission and distribution segments of electricity systems are natural monopolies, as is the function of the system operator. A natural monopoly means a single firm can operate at a lower cost than multiple firms in delivering the same service, or that when numerous integrated companies enter the market, only one will survive. Typically, natural monopoly segments in electricity systems receive revenue from regulated prices that are periodically reset by a regulatory body. To some degree, competition for the market can help improve the efficiency of whatever part of the system is run as a monopoly.

When there is competition for the market in monopoly segments, for example in transmission and distribution, the government bids out the right to manage, operate, and/or invest in a monopoly company for a period of time. Most such cases involve contracting out the running of a distribution company. Transmission company contracts may also be competitively awarded to private firms, as in Chile and in Argentina in the 1990s or in the United States since the early 2000s.

Brazil provides an example of auctioning off additions to the transmission system to the private providers building and maintaining them (e.g., PPIAF 2017). At the initial stage, auctioning a franchise allows the choice of best provider. At the same time, competitive bidding may create incentives for bidders to underbid—either strategically to renegotiate later once they have won the franchise, or as a result of the “winner’s curse”: the possibility that winning bidders are just the most optimistic ones. For the arrangement to work well, it is important that contracts are well designed and supervised so that the provider can be held to its original promises.

The quality of subsequent regulation also matters. This is particularly true for full concessions, where providers are responsible for both operations and investment. Typically, changes in demand and cost conditions require that a regulator, whether an independent agency or a ministry, reset concession terms (e.g., tariffs) every few years. Overall, contracting out competitively to competent providers requires adequate governance and capacity in the contracting agency and the regulator so that the whole arrangement delivers on its promise. Customers pay for monopoly segments of the system in the form of some regulated charge or levy.

Contracting out monopoly segments of electricity systems like distribution to the highest bidder can raise productivity and improve quality of service—if contracts are well designed and supervised and if regulation works adequately (Schwartz and Guasch 2013; Gassner, Popov, and Pushak 2009). Privatized distribution companies are typically characterized by cost-covering tariffs. Private ownership may have insulated companies from political pressure to lower prices, or private investors might have simply bought into companies where governments were willing to set and enforce cost-covering tariffs (World Bank 2019). Yet, well-run, state-owned monopolies can do just as well (World Bank 2019). Still, having the option to contract out and to do so at times may itself stimulate state-owned firms to shape up and improve performance.[12]

Open Access

Overall, competition among distribution and transmission companies has seen limited uptake. In the 1990s, several countries, particularly in Latin America, awarded distribution companies to private concessionaires. Yet, since the 2000s few countries have embarked on new concessions for distribution companies. Transmission has, in most cases, remained state owned (World Bank 2019).

A competitive market requires new and better service providers to deliver services to customers and replace less efficient competitors. The delivery of electricity usually involves using "wires," that is, the electricity grid. The grid is a natural monopoly and whoever controls it, most likely the system operator, can grant or deny access to providers. Hence, the importance of "open access": nondiscriminatory access to the grid based on the rules of the market, including system security constraints. Such nondiscriminatory access is most beneficial, or full (ESMAP 2013), when the market rules themselves are optimal; less so when the rules provide special treatment (e.g., for inefficient legacy contracts under PPAs). Figure 3.1 illustrates a power sector structure allowing open access to power grids.

Making full, open access a reality is equivalent to structuring, designing, and governing the best possible market. This includes minimizing conflicts of interest for those controlling access to the grid. Essential are, of course, charges that pay for the grid—typically regulated fees plus some congestion rents in the case of markets with nodal pricing. Expanding the grid to provide access to new providers is another topic requiring sound system expansion planning that trades-off the cost of grid expansion against the cost of generation.

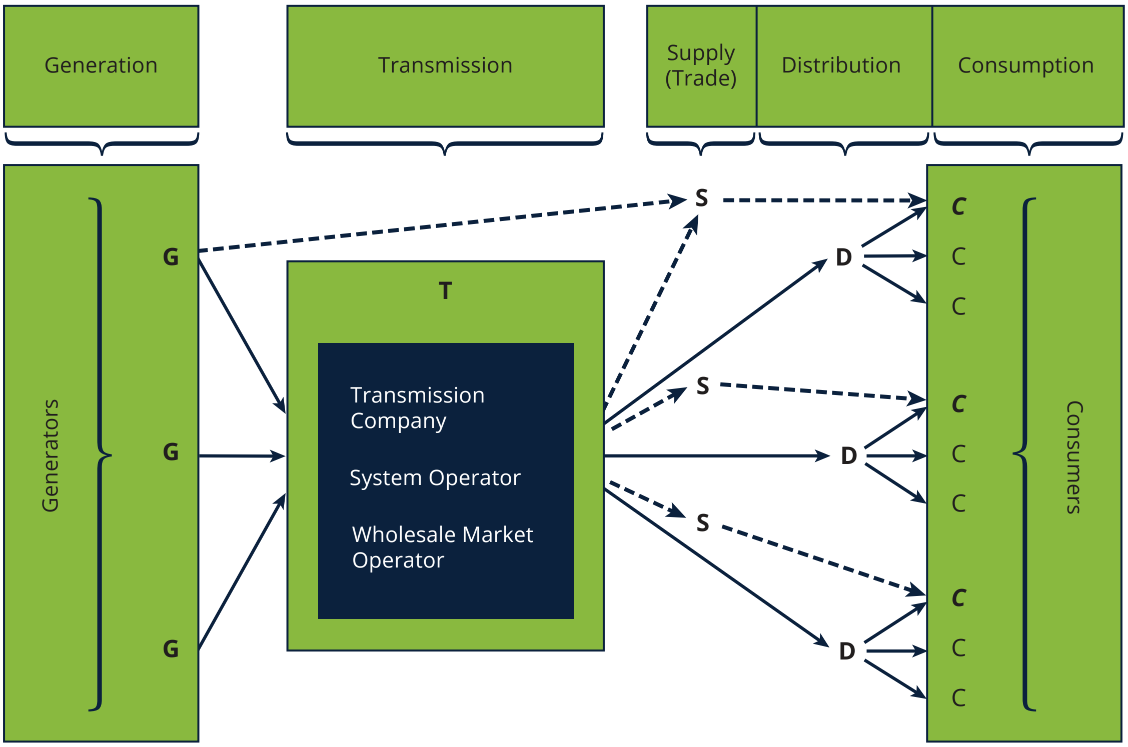
One feature of open access systems is the ability of at least some buyers and sellers to conclude contracts freely. Contracts may be for physical delivery or purely financial hedges. As discussed in the section on sequences of markets, such contracts are fundamentally equivalent in an efficient market design.

System Planning in Market Systems

Electricity markets combine optimization models with market forces—where consumers and producers exercise choice. Optimization models and analytics support both day-to-day management and planning in the long run.

FIGURE 3.1

An Example of a Power Sector Structure Allowing Open Access



C = Consumption; D = Distribution; G = Generation; S = Supply (Trade); T =Transmission
Font coding used for market levels:

Bold G, T, S, and **D** = Wholesale
Bold Italic C = Contestable retail (open access eligible)
Plain C = Captive retail

Source: ESMAP 2013.

Planner's tools for day-to-day management:

- One core issue for electricity market design is managing imbalances in the interconnected electricity system second by second. There is currently no practical way by which entirely decentralized contracting among market participants achieves an outcome where demand matches supply by the second and the physical constraints of the transmission system are respected, all while keeping frequency and voltage within very narrow bands.[13]
- At the heart of electricity systems are computerized optimization models. When markets are introduced, bids by generators and customers in the wholesale market provide the input values for the models. The output is a system of prices that optimizes dispatch in the sense that the cheapest generators are dispatched and the consumers with the highest willingness to pay (WTP) are served.[14] This type of

market, assisted by an optimization program, is often called a market clearing engine or smart market.

Planning for the long run centers on transmission expansion. The shape and build-out of transmission systems for electricity require basic planning decisions. These interact with decisions about generation investments in two ways:

- First, generation and transmission are complements. One needs both to transport and sell electricity. In markets, ideally the choice of optimal size, technology, and location for a generation plant is left to market forces. Yet, this also depends on planning decisions about transmission. Markets will only lead to optimal outcomes if participants correctly anticipate how transmission systems will be built out. The best one may be able to do is provide indicative planning for the build-out of the transmission network in consultation with the generation providers.
- Second, transmission and generation are also substitutes. For example, expanding a transmission line may facilitate bringing in more power from afar instead of building a new power plant nearby. To some degree, transmission investment is thus in competition with generation. Yet generators get paid by prices set in markets; transmission assets get paid for by prices set by regulators.[15]

Governance Arrangements

Overview of Governance Issues

A number of governance issues need to be settled when designing the foundations and operations of an electricity market. The basic governance arrangements for the full array of players and rules are usually set by legislation. Regulatory bodies and implementation agencies are needed to implement the rules. Regulators may also have some circumscribed powers of rulemaking to deal with required adjustments to the rules as unexpected issues in market design need to be addressed. Limited regulatory functions may be performed by players like system operators: for example, the determination of price caps for wholesale markets. Five important governance issues are described below.

BUILDING BLOCKS OF MARKET STRUCTURE

Legislation and regulation create the building blocks of a system featuring competition in the market, notably the relationship of competitive segments (generation and supply plus associated financial markets) with monopolistic segments (market infrastructure, transmission, and distribution). Market infrastructure includes the system operator that is in charge of dispatch, and the market operator that runs the market clearing engine. As with any market, contractual infrastructure is required, including dispute resolution mechanisms. A settlement administrator assures correct billing and collection in the wholesale market.

PRICE REGULATION

Monopolistic segments require some form of price regulation to prevent abuse of power. Competitive segments may be plagued by market power. Hence, some form of market monitoring to detect abuse of market power is called for, as well as mechanisms to prevent and penalize it.

CONFLICTS OF INTEREST

Mechanisms are required to ensure that owners of monopolistic segments do not discriminate against certain players in competitive segments. For example, rules are needed to ensure nondiscriminatory access to transmission for generators. Most importantly, the system and market operators should be free from conflict of interest. For example, system operators should ideally be separate from other actors in the electricity system to ensure impartiality.[16] They may also be bundled with a transmission company to minimize coordination problems, when transmission companies themselves do not suffer from conflict of interest, for example, due to ownership of generation companies under a single holding.

SYSTEM MANAGEMENT PROTOCOLS

The system operator dispatches based on market signals. At the same time, system management protocols are required to balance the system second by second. This is laid down in a grid code, which can easily run to hundreds, if not thousands, of pages. These protocols may involve non-market-based deployment of ancillary services. This can potentially interfere with the functioning of the market (Joskow 2006). Therefore, mechanisms to establish and adjust operating protocols to market rules are needed.

QUALITY REGULATION

All system segments require regulation of relevant dimensions of quality such as safety standards. This could include requirements to insulate power cables or keep them at a safe distance from flammable material like forests. It could also require standards of construction or maintenance for power plants, including rendering them robust under extreme temperatures. Box 3.3 discusses an example of establishing an energy regulator in Turkey.

Similar governance and institutional issues related to power pools have been identified by Oseni and Pollitt (2014):

- Greater trade openness leads to more cross-border trade in electricity. Both expanded bilateral power trading and formal power pools require precommitment to free trade to be successful. Free trade arrangements generate a reasonable level of trust to promote the development of a power pool.
- Strong, efficient, and independent institutions are essential for an effective and functioning power market. An integrated power pool needs an efficient operator to oversee and sanction the activities of participants, and to prevent predatory pricing, nondisclosure of capacity, and other forms of unruly behavior.

ESTABLISHMENT OF TURKEY'S ENERGY REGULATOR (EMRA)

In Turkey in 2001, the Electricity Market Law (EML) was passed as a fundamental approach to easing the burden of the power sector on the public budget. The law also established the Energy Market Regulatory Authority (EMRA) as an independent and financially autonomous regulator of power, gas, petroleum, and liquefied petroleum gas, supervised by the EMRA board. EMRA is responsible for preparing and implementing secondary legislation; authorizing market participants; approving and publishing tariffs; monitoring and supervising market participants; conducting technical, legal, and financial audits; settling disputes; approving, amending, and enforcing performance standards; and, where necessary, applying sanctions (Vagliasindi and Besant-Jones 2013).

EMRA issued new balancing and settlement regulations in April 2009 to improve the function of the wholesale electricity market. In December 2009, the market moved from monthly settlement to hourly settlement. This reform was undertaken prior to the World Bank's Turkish Programmatic Environmental Sustainability and Energy Sector Development Policy Loan (World Bank 2013).

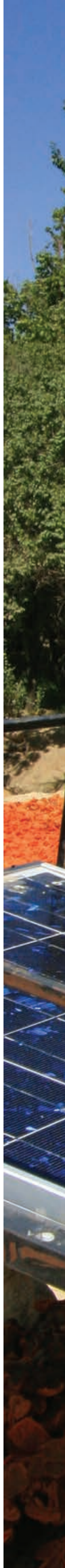
- The viability of an international power pool should be evaluated in advance by a proper cost-benefit analysis.
- Trust building around electricity trading is possible even between countries with a history of conflict.

Design Options for Implementing Agencies

The institutional incarnation of governance arrangements varies by jurisdiction. For example, rules may be set out in laws or decrees. It is recommended that regulatory bodies are provided with a certain level of budgetary and staffing independence. System operators, market operators, and settlement administrators[17] may be housed in one or separate organizations.

To strike a balance between accountability and autonomy of agencies, several tools exist:

- The mandate of an actor like a regulator or system operator needs to be established. This includes setting out goals and responsibilities and available tools to fulfill them: for example, whether system operators can use fees as penalties for nonperformance by market participants.
- Process requirements such as rules governing the transparency of decision-making are yet another tool to enhance accountability, including reporting and auditing obligations. Obligations to consult stakeholders, for example through hearings, are desirable.
- Budget rules can be used to grant and circumscribe autonomy. For example, a system operator may be authorized to obtain income from fees levied on participants in the electricity system.[18] This would make it independent of fiscal appropriations. At the same time, the expenditure budget may be controlled by an oversight body such as a regulator or even a legislative body. This would circumscribe autonomy and enhance accountability.
- Key staffing rules are equally relevant. For example, appointment of board members and top management of a regulator, system, or market operator could be made by a political body like a parliament of the relevant jurisdiction, or the executive, or some special body. Longer terms for appointees provide more autonomy. Staggered appointment of board or commission members may provide some insulation from one-sided political influence.
- Conflict resolution principles and mechanisms can provide autonomy: for example, by limiting personal liability of regulators. Dispute resolution fora, including courts or arbitration mechanisms, can enhance accountability.

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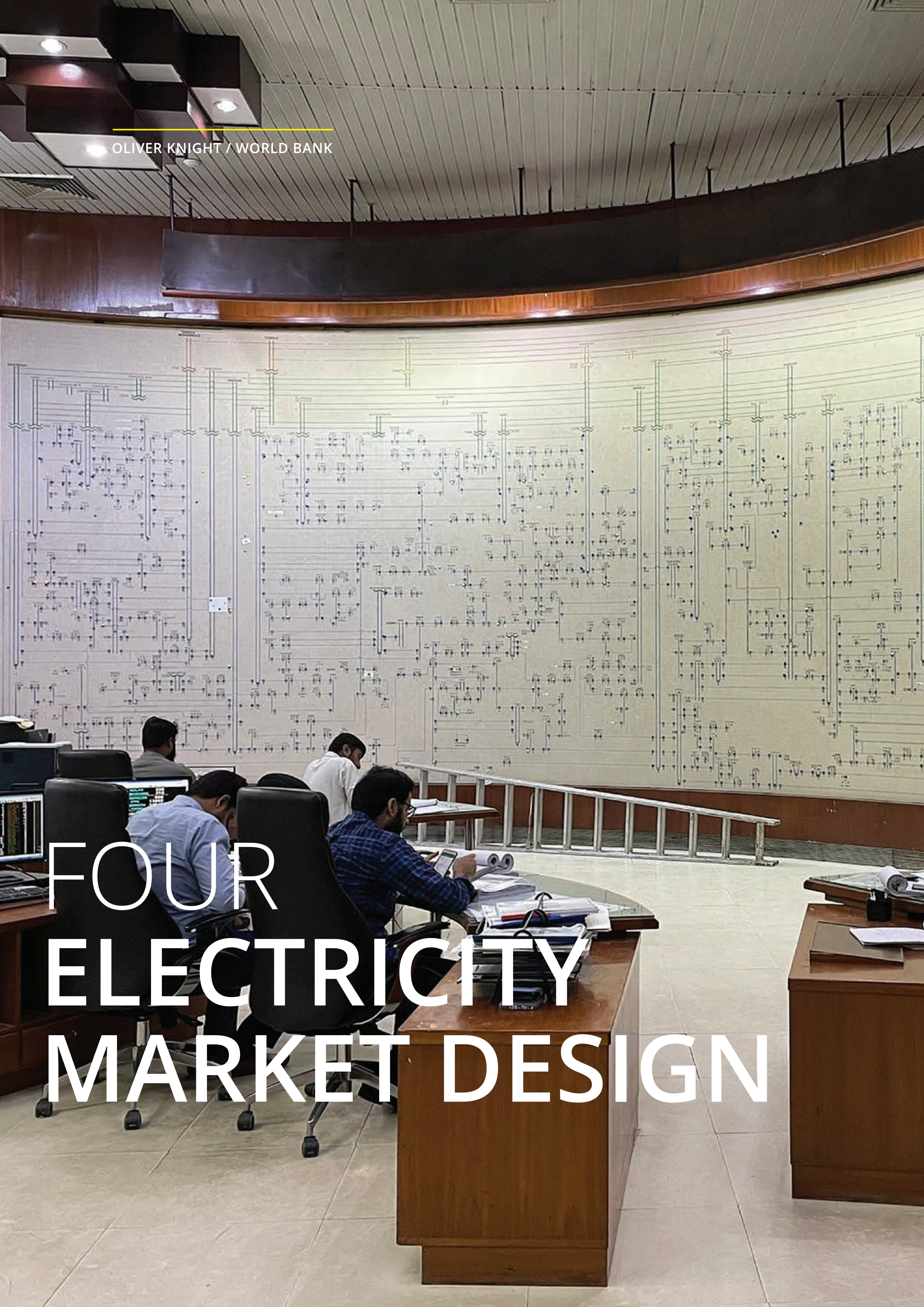

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FOUR
ELECTRICITY MARKET DESIGN

The search for competitive markets may motivate reform and force policymakers to address basic problems. However, replacing the vertically integrated sector framework with an unbundled market structure is not in itself sufficient for an electricity market to function. Power markets promise the benefits of transparency, efficiency, and flexibility; but wholesale market design is crucial for realizing these opportunities in two key regards. In the operational sense, electricity market design defines the protocols for dispatching electricity in a reliable and economic fashion. At the same time, market design determines the long-term landscape of financial incentives and rules for eligibility of investments in resources that ensure a reliable and secure system. The dual role of electricity markets—simultaneously operational and financial—is a defining characteristic of electricity market design.

In addition, many countries are considering various policy solutions to address the challenge of decarbonization and climate change, and market solutions can play an important role in the mitigation strategy. The rapid expansion of new technological solutions, including variable renewable energy generation resources, provides both challenges and opportunities for market design options that elevate the importance of ancillary services.

As there is a wide range of motivations, contexts, and starting positions for market development, there is an equally wide range of market design options for countries to choose from. Yet certain common objectives are expected from the market, namely:

- Promoting efficient operation of power systems;
- Creating clear and effective incentives for investments;
- Improving reliability and cost-effectiveness of electricity services;
- Expanding energy access; and
- Encouraging innovation and reducing the environmental impact of the electricity sector.

Not every objective is weighted equally for every single country, and market design choices will depend on what objectives are considered primary and/ or more urgent for a specific country. All market design choices, however, consist of a menu of four main design elements. Policymakers and regulators therefore must pay close attention to these four market design issues, which are the bedrock of electricity policy objectives:

- Operations: What market design ensures that the overall power system operates efficiently on a day-to-day basis?
- Investments: What ensures that the required investment is forthcoming and efficient?
- Ancillary services: What mechanisms assure supply and demand balance second by second and protect against system collapse?
- Market power: What mechanisms mitigate the abuse of market power?

Operations

Optimal Dispatch in the Real-Time Spot Market

The true spot market is the real-time market that determines actual, physical dispatch. It is also called the balancing market in Europe. Generators bid volumes and prices at which they are willing to sell. In the case of cost-based markets, they submit data on their marginal costs that the system operator audits. Customers may bid how much they are willing to buy at what price,[19] or demand forecasts are used. Based on these inputs, an optimization program calculates optimum dispatch and the corresponding volumes and prices taking the transmission system and security constraints into account.

The standard merit-order dispatch arranges generators starting with the lowest variable (marginal) cost until supply equals demand given the total capacity of the system.[20] Dispatching the lowest variable cost[21] generator first is efficient as its fixed costs have already been incurred.

For some types of generation, intertemporal optimization issues arise. Some power sources are energy-limited, such as a battery or a hydro reservoir. Some take time to ramp up or down. There is then inertia in the system. Some have one-time start-up costs, regardless of how long they are needed, and some have minimum operating levels. In all these cases optimal dispatch may need to consider what happens in the future. For example, energy-limited sources of power like hydropower or, at smaller scale, batteries, have marginal costs that are close to zero. Yet, because they can only provide a limited amount of energy before having to be refilled, they are best dispatched when they replace the energy source with the highest marginal cost (the opportunity cost of the energy-limited generation source). They are most valuable when they are dispatched in peak periods, which may lie in the future.

Types of Markets

BID-BASED MARKETS

Most systems allow generators to formulate bids freely. There are two types of basic bidding rules for generators. Under both, the cheapest generators get dispatched. Under pay-as-bid, the dispatched generators get paid the price they bid. Under a pay system based on marginal price, all dispatched generators get paid the same price—the one that matches demand and supply overall.

Under the pay system marginal price rule, generators have an incentive to bid their true marginal costs. Why? If they bid more, they risk not getting dispatched. If they bid less, they risk losing money when they do get dispatched. When dispatch happens, cheap generators have bid a low value and may receive a much higher value if the marginal generator is much more expensive. This has led to arguments that cheap generators are being overpaid and that the pay-as-bid approach should be used.

Two basic problems are encountered with the pay-as-bid approach. First, the generators with the cheapest variable cost have the higher fixed costs and need a spread over variable costs to cover fixed costs. This means they are not necessarily being overpaid. Second, if one changes the bidding rule, one also changes bidder behavior. Under pay-as-bid the cheap generator will try to guess what the highest bid will be. Then it will try to bid just barely below that value. If the generator guesses right, the outcome is the same as under the pay system marginal price: everybody bids at the level of the price that balances demand and supply overall. However, the guessing game introduces extra costs due to the extra use of forecasting models and increases the chance of bidding mistakes leading to inefficient outcomes.

Some bid-based systems focus on allowing bidders to submit price-quantity pairs up to shortly before the actual dispatch. In these systems the interaction of bidders is meant to figure out optimal dispatch as much as possible. This is the case for most European systems, and also for countries such as Australia and New Zealand. Several other bidding systems focus on bidding in day-ahead markets, and allow more complex bid formats: for example, the inclusion of start-up costs or ramp rates in addition to price and quantity pairs. Optimization of the actual dispatch then becomes the task of the smart market—the computerized optimization system. This is the model for US systems.

The difference between the European and US approaches can be illustrated by how they deal with start-up costs—the so-called unit commitment problem. Under the former approach, bidders need to figure out whether it is worth it for them to incur start-up costs. The system operator just receives price-quantity bids. Bidders have an incentive to behave efficiently, but they may make mistakes in forecasting future demand for their units (generators). Under the US approach, bidders submit data on price, quantity, and also start-up costs in the day-ahead market. Optimization is carried out by the smart market. The basic trade-off: bidders may make mistakes, but the optimization model might not find the best solution (global optimum) when running mixed-integer linear or nonlinear optimization models.[22]

COST-BASED MARKETS

In a cost-based market, generators are required to submit their marginal cost, which may subsequently be audited. One can think of this as placing a cap on allowed bids. Generators have limited room for strategic behavior and thus the exercise of market power. Generators compete to be available for dispatch. This is the case for most Latin American markets (except Colombia) and for South Korea.

These systems give competing generators an incentive to cut costs and to be available for dispatch. Yet, they do not provide incentives to reveal the best information about the costs that generators possess. Costs are provided by generators and audited, presenting system operators with the challenge faced by price regulators: namely, how to assess whether the audited costs are efficient. Decentralized trading cannot take opportunity costs and intertemporal trade-offs into account. Real-time, demand-side bidding is impractical as system operators cannot reasonably estimate the opportunity costs of customers, which drive price-sensitive, real-time demand.

The difference between cost- and bid-based approaches can be illustrated with the example of energy-limited power. Bidding systems can handle this problem as bidders will want to dispatch energy-limited resources for the highest possible price, which will be obtained in peak periods. In cost-based systems, some form of optimization model must figure in the intertemporal opportunity cost of such resources.

REGIONAL POWER POOLS

Electricity trade across inter- or intrastate borders can reduce costs and enhance reliability by allowing imports and exports. Short of introducing competitive electricity markets, many options exist to generate some benefits from trade. They range from limited cross-border transmission infrastructure that may be used ad hoc, to rule-based, interconnected "power pools" that come close to resembling competitive markets.

Trade in power pools holds the potential to reduce costs and thus tariffs or fiscal outlays. Exports from low- to high-cost areas lower operating costs. Larger trading areas may allow generation investors to exploit economies of scale and build plants with lower unit costs. Sharing of reserves can enhance security of supply. Joint system planning may also help save on system expansion costs and allow for better integration of intermittent renewable energy sources. The need to agree on cross-border rules may help improve the quality of rules governing trade.

Trading in power pools is often done under regulated pricing systems, with limited use of competitive markets. Prices and volumes may not correspond to efficient dispatch based on merit order. Governance arrangements are particularly challenging for trade across national boundaries, as countries have to cede some control—ideally to a supranational system operator—and enforcement of payment discipline between countries is often hard. Mostly for political reasons, actual cross-border trade lags far behind potentially gainful exchange. At the same time, power pools may be stepping-stones toward creating full-fledged markets with meaningful competition among multiple players, as was the case of the PJM pool in the United States.

Regional power pools exist between a number of countries, between Malaysia and Singapore for example; or within countries between areas run by different system operators as in the Western Interconnection in the United States, within India, and within China. In developing countries, the most advanced trading arrangement is the Southern African Power Pool (SAPP), with 12 member states centered around South Africa. Central America features a pool of six countries. The West African Power Pool (WAPP) comprises 14 nations, but is currently limited in bilateral trading given the relatively weak physical interconnection among the countries. However, this is rapidly changing. Others, including the Eastern Africa Power Pool, the Maghreb Electricity Committee (Comité Maghrébin de l'Electricité, COMELEC), and the Pan-Arab Electricity Market, are in early stages of development. In addition, there are several smaller, mostly bilateral trading arrangements in Asia as well as in Latin America.

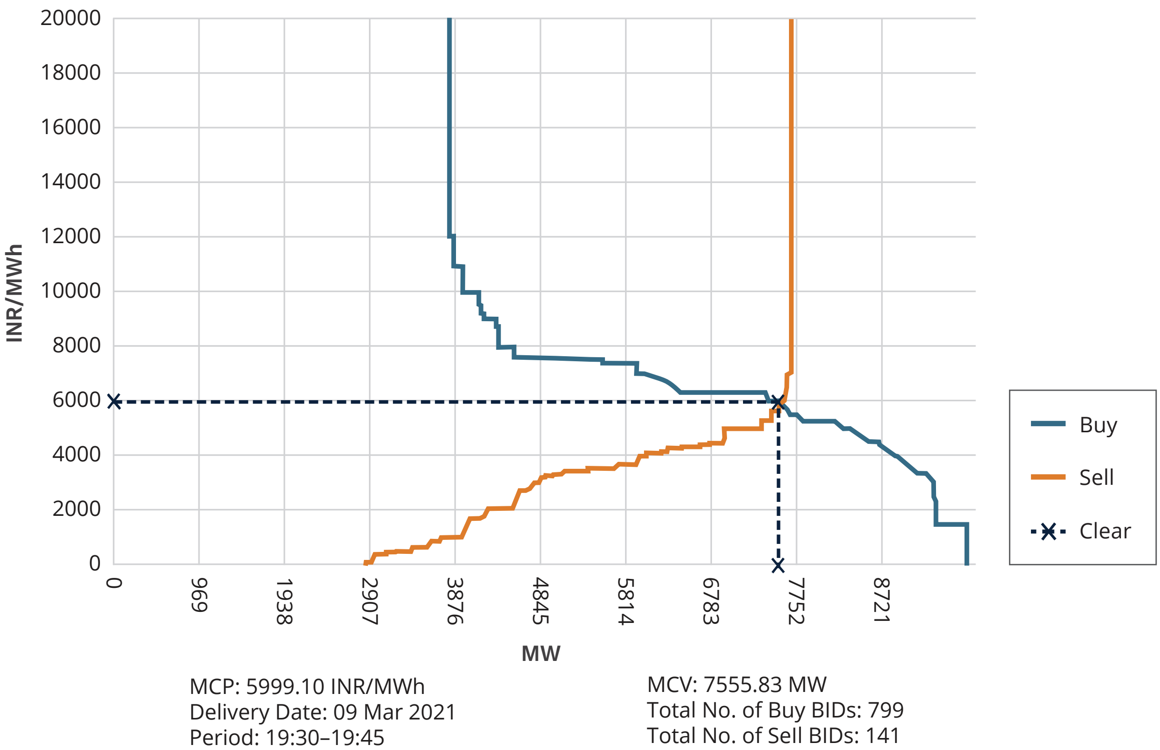
Price Formation in Markets

The price formation process is important for providing signals to market participants regarding efficient system use and investment in new capacity. Suppose generators are only paid when they actually get dispatched (as in an energy-only market). In such a market, most of the time, price equals the marginal cost of the most expensive dispatched generator's willingness to pay (WTP), and at the same time the WTP of the marginal customer. All other served customers have a higher WTP as in a standard microeconomic model that maximizes overall benefits from trade. In a wholesale market, generators will reflect their marginal cost of supply through a set of sell bids in increasing order of cost. Meanwhile, customers such as retailers and industries would express their WTP through a set of downward sloping bids (see Figure 4.1).

Market design should provide the option for generators to submit negative price bids.[23] For example, combined heat and power plants may be producing heat and may have inflexible concurrent power production. They would then have an incentive to bid negative energy

FIGURE 4.1

Demand-Supply (Buy and Sell) Curve for the Indian Energy Exchange



Note: Day-ahead market clearing in the Indian market. Market cleared for Rs 7,555.8/MWh in this instance at Rs 5,999/MWh or $82/MWh ($1 = Rs 73). MCP = market clearing price; MCV = market clearing volume; MWh = megawatt-hour.

Source: Day-ahead market data from the Indian Energy Exchange, accessed on March 9, 2021.

prices to ensure that heat production need not be curtailed. Also, some plants (e.g., nuclear facilities) cannot easily ramp up or down. They may need to sell temporary excess production at negative prices to stimulate consumption. By the same token, intermittent renewable sources should optimally not be given so-called grid priority as there is no reason to bid lower than zero.[24]

Sometimes—at peak times—customers may be willing to pay more than the marginal cost of the generator with the highest marginal cost, implying that all generators will be dispatched and the system reaches its capacity limit. At a price equal to the marginal cost of the most expensive generator, customers want to buy more than the system capacity permits. In a normal market with price-elastic demand, the price then rises such that customers with the lowest WTP drop out until demand is equal to supply. These periods of high prices above marginal cost allow investors to cover fixed costs.

Price formation in electricity markets has special features, which include:

- Demand is usually highly price inelastic in the short term. Most people and businesses do not see prices in real time. They just switch on their power when they want it. Currently, the system operator does not have the technology and information to remotely switch off individual customers or their appliances according to their WTP when capacity is scarce.[25] Technically speaking, when the system reaches its capacity limit and the limited real-time, demand-side management options that currently exist have been exhausted, the supply curve is vertical as is the demand curve (see Figure 4.1). At peak times the demand and supply curves may then not intersect. Unconstrained bidding would generate an infinitely high price. The market by itself does not generate a meaningful price. Physically, the system operator has to "shed some load," that is, cut some customers off so that demand and supply match. Rationing, rather than response to price, balances demand and supply. In the long run it may be possible to do away with this way of rationing if demand can be made more price responsive. This could become technically feasible as new types of meters, sensors, and control technology allow widespread, real-time demand response to prices.
- When load shedding happens, all generators produce as much as they can and need to be paid. The market price hits the price cap and remains at that level. Hence, a regulated price is used that tries as best as possible to mimic what happens in a normal market, that is, to reflect the WTP of the marginal customer that can just be served. In the language of power markets, this is called setting the price at VOLL, the value of lost load; or, in economic language, the opportunity cost of not getting electricity.[26] This is also called scarcity pricing.
- The higher the price cap, the less load shedding is needed for generators to obtain enough revenue to cover fixed costs. The price cap thus reflects a reliability standard, which may be expressed in the expected aggregate time of load shedding over a specific time period, for example, one day in 10 years. In practice this is often translated into a reserve margin requirement.[27] It makes no economic sense to rule out load shedding entirely, because it would require investments for very rare circumstances such that extra costs would exceed the extra expected benefits. At whatever level—above the highest marginal cost—the price cap is set, it allows generators to cover their fixed costs efficiently, for a given reliability standard.[28]

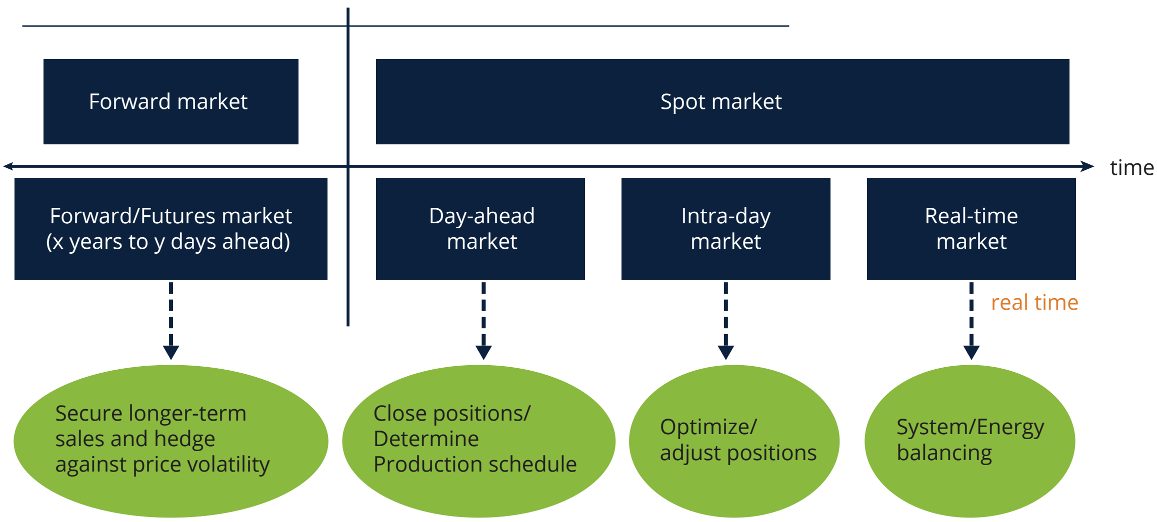
Sequence of Markets and Intertemporal Hedging

An analogy may help explain the basics of electricity market design. Consider the market for passenger seats on airplanes. Passengers buy seats in advance of flying: a forward contract. When they show up at the gate, it may happen that the flight is overbooked. Airline staff at the gate may then hold an auction (real-time balancing market) that establishes the price at which a sufficient number of passengers decide to take another plane. They then get paid the price by a "settlement administrator," in this case typically a voucher for some other flight.

Electricity markets feature a sequence of markets (summarized in figure 4.2). The real-time market determines actual dispatch and is thus a physical spot market. Today it is possible to run real-time markets as frequently as every five minutes, as do most US markets and Australia. In Europe, many real-time markets run every 15 minutes. Some countries feature 30-minute intervals (e.g., Japan) or hourly intervals (e.g., Colombia) between market runs.[29] Market clearing granularity can significantly reduce the system balancing needs, reducing the barriers to integration of variable renewable energy.

As in many other sectors of the economy, most markets trade financial contracts that allow hedging of risks associated with physical dispatch in the real-time market. Financial markets exist for contracts with different maturities. In some markets very-short-term forward trading is possible before the real-time market, until so-called gate closure. This may be as close as 30 minutes before the real-time market, as is the case in France.

FIGURE 4.2
Electricity Market Timeline



Source: Petrov 2021.

Many systems feature a mandatory day-ahead market that helps system operators prepare for dispatch. In some systems, the US markets for example, system operators use the day-ahead market to provide instructions to generators to incur start-up costs ahead of the real-time market. Australia, on the other hand, has no mandatory day-ahead market. In many European systems generators take the risk of making their own start-up decisions.

Various financial contracts, for example forward contracts or options with longer maturities, are typically traded. Financial contracts are most widely available for shorter maturities, say one to three years. Contracts of such maturities are often sold on formal power exchanges, such as the European Energy Exchange or NASDAQ. Contracts with longer maturities are available in various markets but are typically traded "over the counter" rather than on exchanges.

Imbalance Settlement and Forward Markets

Fundamentally, the existence of real-time spot[30] markets makes fulfillment of long-term contracts easier. For example, when a generator is unavailable due to maintenance issues, it can still fulfill a long-term contract with a customer by buying the requisite energy in the spot market. Likewise, a customer who has over-contracted energy can sell off surplus in the spot market. This way the spot price drives the price of hedges. Box 4.1 illustrates the relationship between financial and real-time markets. At the same time, it sets out the basics of running market systems as so-called gross pools or net pool, as well as the basic difference between physical and financial contracts.

Adequately designed, both gross and net pools yield the same outcome and produce the same incentives. In practice, some countries maintain a system of penalties in net pools for purchases in the spot market. The UK's former New Electricity Trading Arrangements (NETA) market featured such penalties. Recently they were abolished as it turned out they penalized small market participants and led to extra costs as generators made costly efforts to avoid imbalances that forced them to buy in the spot market (Shuttleworth and Mckenzie 2002).

In principle, market participants have the option to hedge price fluctuations by concluding long-term contracts such as forwards. For example, in the Philippines almost 90 percent of spot sales were covered with hedges of about one-year maturity in recent years (Rudnick and Velásquez 2019a). In practice, it may be hard to find counterparties willing to enter into contracts with maturities above two or three years (IEA 2016). Liquidity, the ability to get in and out of contracts, may be limited. Renewing contracts may thus be difficult, giving rise to a rollover risk.

To develop a sufficiently deep and liquid market for hedges, market participants need to believe that market rules are reasonably stable. The expectation that scarcity prices are a real possibility provides strong motivation to buy hedges, as in the Texas market in the United States. On the other hand, political pressure to undo price spikes may undermine the willingness to buy hedges. Also, regulated distribution companies that perform retailing functions may not buy hedges because they may fear being accused by customers and regulators of raising costs excessively.

BOX 4.1

WORLD BANK

FULFILLING LONG-TERM CONTRACTS IN MARKETS IN GROSS AND NET POOLS

Suppose a generator concludes a forward contract with a distributor for delivery of 1 gigawatt-hour (GWh) at a price of 4 cents/kilowatt-hour (kWh)—for a total value of $40,000. At the time of dispatch—in the real spot or balancing market, sometimes called the regulation market—it turns out that the generator can only produce 0.9 GWh, but the distributor needs 1.1 GWh. The spot price turns out to be 5 cents/kWh, reflecting the overall demand and supply balance at this time.

In a so-called “gross pool,” generators and distributors sell and buy all they produce or need in the spot market. The generator sells 0.9 GWh at 5 cents/kWh and receives $45,000. The distributor buys 1.1 GWh at 5 cents/kWh and pays $55,000. The forward contract is then settled in the form of a so-called contract for differences (CfD). Relative to the forward contract, the generator benefits from a higher price in the spot market and thus needs to compensate the buyer for the price difference (5 – 4 cents = 1 cent/kWh) applied to the volume of the forward contract (1 GWh). The generator thus pays the distributor $10,000. The net result: The generator earns a net of $35,000. The distributor pays a net of $45,000.

(*continues on next page*)

BOX 4.1 (*Continued*)

Physical delivery happens in the spot market. The CfD is deemed a financial contract. If the volumes had not changed relative to the forward contract, the CfD would have perfectly hedged their respective position against price changes in the spot market. CfDs hedge against overall market price risk, but leave the contracting parties exposed to volume changes. This provides good incentives for the contracting party to control what they can to some degree, namely volume, while shielding them from the risk they take as price takers in the spot market.

In a so-called net pool, the parties first settle the forward contract. The distributor pays the generator $40,000. The generator delivers 0.9 GWh out of its own production and has to buy a make-up volume of 0.1 GWh in the spot market at 5 cents/kWh for a total sum of $5,000 to fulfill the promise under the forward contract. The net revenue of the generator is thus $35,000. The distributor needs to buy an extra 0.1 GWh from the spot market at 5 cents/kWh for a total of $5,000. Its overall payment is thus $55,000. The forward contract is deemed to be a physical contract here.

Congestion Management and Pricing

NODAL PRICES

If there is no congestion in the transmission system, all agreed trades can be executed at the same price throughout an interconnected system.[31] When the limits are binding, the system is split into several submarkets. Each node in the system where individual transmission lines interconnect can be regarded as a marketplace. Demand and supply conditions at each node lead to a different price at each.[32] The price differences between nodes reflect congestion and transmission losses. Such prices are often called nodal prices or locational marginal prices.

Nodal prices reflect both the physics of power flow and the economic incentives of consumers and producers at each node. The theory of price formation that renders the economics and physics of electricity systems compatible is attributed to Schweppe et al. (1988). It takes into account the fact that electricity flows along the path of least resistance. Any injection or withdrawal of electricity at any node changes power flows throughout the whole interconnected AC system (loop flows). At the same time, prices need to reflect demand and supply conditions at each node. Systemwide, nodal prices guide the decisions of consumers and producers to maximize net benefits for market participants. Note that one unusual aspect of nodal pricing is that, between some nodes, electricity flows from nodes with high prices to nodes with low prices. This reflects the physics of power flow.[33]

Nodal prices provide the best possible price signals to consumers and producers. Nodal price systems exist in the United States. Emerging markets, for example, Chile and Peru, feature nodal prices. To deal with the risk of changing nodal prices, markets may provide hedging instruments, for example, so-called financial transmission rights (FTR) that lock in a price difference between nodes.

However, there are some potential drawbacks with the nodal pricing system:

- There may be load pockets behind transmission constraints, where some generator is able to exercise market power that it does not have in the market as a whole. Having said that, in zonal markets such generators may still be able to exercise market power if they foresee when congestion might occur and bid a higher price, thus raising redispatch cost.
- Traders might like zonal pricing because it allows more liquid markets to exist and thus improve hedging options. At the same time, their hedges may not cover the risk of varying redispatch costs. In the nodal system, hubs with high liquidity will tend to develop, but there would be a "basis risk" for those trying to hedge prices at nodes with low contract coverage by resorting to contracts traded at the hubs.
- People in one area of a country may object to pay prices that differ from what people pay elsewhere. People do face price differences in other markets that are due to transport cost differentials, but the issue in electricity markets may be more politically salient. If congestion is a rare event, it may favor zonal pricing, but that may in itself be a sign of overcapacity. Generally, the arguments tend to favor nodal prices. These also provide a signal on where to locate new generation or how to build out the transmission system.

ZONAL PRICES

Most markets are, however, divided into uniform pricing zones covering a country, a province, or some other geographic area. Such zonal prices do not reflect transmission constraints. For example, Germany plus Austria is one price zone, even though the countries feature many nodes. Brazil is an example of an emerging market with zonal pricing. Forward markets conclude contracts ignoring the possibility of congestion. When there is no congestion, this does not matter. In some zonal markets (such as in Nord Pool), different zonal areas may be activated by system operators when congestion occurs, approximating a system of nodal prices—known as market splitting.

With congestion, the following type of problem may arise under zonal pricing schemes. Imagine a simple system with two nodes, A and B. At node A there is cheap generation and little demand. At node B, there are expensive generators and significant demand. In a zonal market, forward markets have contracted the cheapest generators to supply load (demand). However, when the transmission line between the two areas is congested, some of the cheap generation at node A cannot be used to supply demand at node B. What was contracted cannot be implemented. The system operator needs to intervene to balance the system. It will instruct the most expensive generation at node A not to produce and will instead dispatch the least expensive generation at node B to meet demand at that node. Compared to the contracts concluded in forward markets, generation costs are higher, and the market price generated in forward markets does not generate enough revenue to cover the costs of additional generators dispatched at node B. This may be called the "redispatch cost." It is typically charged on some pro rata basis to consumers across the pricing zone. In a system with nodal pricing with congestion, the price at node A would have fallen and risen at node B, allocating the costs of congestion to those who cause it. With demand response, there would be more use of cheaper generation at A and less consumption at B. Nodal pricing schemes are, in principle, considered more efficient.

CONGESTION RENT

When there is congestion, the sum of all trade leaves a net surplus, or congestion rent, also called merchandising surplus. Ignoring the effect of losses, congestion rents are simply the difference between payments made by loads and the revenues received by generators. In theory, in the absence of congestion, all locational marginal prices would be equal and congestion rents would be zero. Theoretically, an optimally built-out transmission network generates a congestion rent that covers the full cost of the transmission system. One could even decentralize investment in individual transmission lines with costs recovered through congestion rents (Biggar and Hesamzadeh 2014).[34] In practice, it has not been possible to fully define capacity rights and rights to congestion rents and to solve attendant contracting problems. Also, transmission systems tend to be overbuilt: for example, to render them more resilient to the failure of individual lines. There is then less congestion on average and the congestion rent often covers only about 20–25 percent of the cost of transmission (Pérez-Arriaga, Rudnick, and Rivier 2009; Metcalf 2010). The rest needs to be paid for by a levy on market participants. Still, it is an efficient way to remunerate transmission owners. Also, it is never optimal to reduce congestion to zero at all times, because the cost of extra investment will be of some significance, while the benefits of extra transmission go to zero as congestion diminishes.[35]

Investment

Markets delegate investment decisions to competing firms, meaning investments are no longer managed by a regulated monopoly. Policymakers need to be comfortable that market mechanisms will lead to adequate levels of capacity as well as an efficient mix of cost-effective base-, mid-, and peak-load generation plants.

Price signals for optimal investments are generated in markets, where prices in markets vary over time and by location. Such variability creates risks for investors that they need to be able to hedge or bear. Price volatility is increasing as intermittent renewable generation expands, accentuating the need for financial hedges.

The crux of market design is how fixed costs, that is the capacity costs of power plants, are covered. Various capacity remuneration systems (and hybrids thereof) exist. The following three basic approaches are set out:

- Energy-only markets
- Capacity markets
- Mandated long-term hedging contracts

Energy-Only Markets

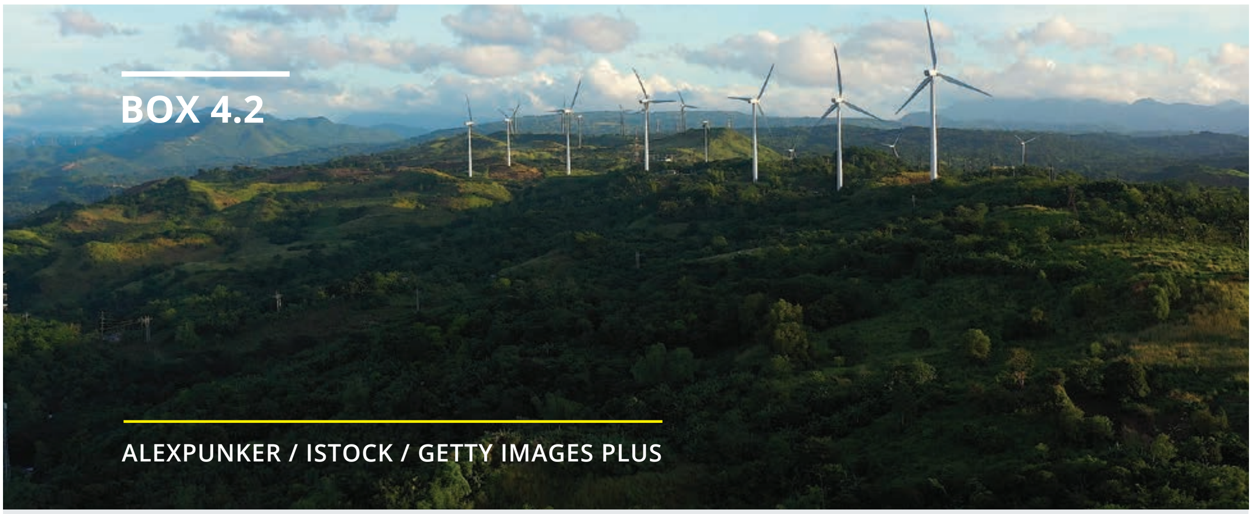
Prices for energy formed in competitive markets that fully reflect demand and supply conditions provide incentives to attain reliability and affordability. In a so-called energy-only market, investors earn revenue when they sell energy. They are not paid an additional payment for the capacity they provide, such as an availability payment under a PPA. Investors are dependent on revenues from the sale of energy to cover both fixed and variable costs.

As long as the price of energy is set by the highest marginal cost generator, all generators with lower marginal costs earn some contribution to fixed costs.[36] When the price rises above the system's marginal cost and is determined only by WTP of the marginal customer or VOLL, the peaker plant with the highest marginal costs earns back its fixed cost. All other plants also benefit from this to cover their full fixed costs. (See Stoft (2002) for basic proof that prices in competitive energy-only markets provide the right incentive to invest in an optimal mix of power plants.)

Energy-only markets are found in several European countries, as well as in Australia, New Zealand, the Philippines, Singapore, and Texas (United States). Under an energy-only market, rare price spikes are needed to attract investors. Three basic issues arise:

- Politically, there may be an outcry when prices do what they are meant to—as in the Australian drought-based crisis of 2016–17 or in Texas in 2019 and 2021, when prices rose to the cap of $9,000/MWh (Martin and Malik 2019). Though customers suddenly have to pay significantly more, most of the time they pay less than needed to cover all costs of generation. Still, such systems are politically contentious.
- Investors may have to wait a long time for prices to spike and face considerable uncertainty about cost recovery.
- Generators with some level of market power may have a strong incentive to withhold capacity so that the system resorts to more load shedding and price spikes than are really required. Box 4.2 shows an example from the Philippines on taking measures to prevent withholding capacity.

In principle, these issues can be dealt with if hedging products are well developed. Customers can buy hedges, such as forward contracts, to cover themselves against the



BOX 4.2

ALEXPUNKER / ISTOCK / GETTY IMAGES PLUS

TAKING MEASURES TO PREVENT WITHHOLDING OF CAPACITY

The Philippine spot market is a hybrid between a gross pool for generation scheduling, with bilateral contracts that often include minimum offtake requirements. The power market remains dominated by four major players that accounted for 62 percent of total registered capacity in 2017.

Serious conflicts due to market power abuse have occurred in the past, and new competitors have slowly entered through the largely regulated market of bilateral contracts. For example, allegations of market power abuse prompted market intervention in 2013, and it was later ruled that market players engaged in anticompetitive behavior provoking a sharp price hike (Rudnick and Velásquez 2017).

The Energy Regulatory Commission (ERC) intervened in the spot market by replacing market-clearing prices with regulated rates. The case of the Philippines highlights the importance of developing structures that support competition, and the need for effective monitoring and oversight.

eventuality of price spikes. That means they regularly pay more than the marginal cost. Investors thus receive ongoing contributions to fixed costs and reduce their investment risk. When electricity has been sold forward it also reduces the incentive of generators to exercise market power, because if they help raise the price, they also need to compensate their customers for the higher price.

One option is to cap prices at lower levels in cases of load shedding. Operating reserve pricing is compatible with energy-only markets (Stoft 2002). Under such a scheme, used by the market in Texas (United States), price spikes occur not just in rare cases when actual load shedding occurs, but also when some threshold level of remaining operating reserves is reached. That means prices spike more often and, therefore, need not go as high to allow investors to cover their costs. The 2020 price cap amounted to $9,000/MWh. To this day Texas has made an energy-only market work on this basis. Yet, any step to replace market prices with regulated caps diminishes the value of the price signal to consumers, because it no longer reflects the demand-supply balance as well. For now, this is a limited issue. It would become a bigger one if and when widespread, real-time demand response becomes feasible.

Capacity Markets

Market price caps make pricing politically more palatable but reduce incentives to exercise market power. This has taken place in some Latin American countries, where price caps are set much lower than the scarcity levels reflecting the VOLL for an energy-only market (given a reliability standard).[37] In these situations, investors may not receive enough money to cover investment and operating costs. If this revenue is not adequate, there is a "missing money" problem (Joskow 2013).

To recoup that missing money, capacity markets—or more broadly, capacity mechanisms—have been introduced. Their detailed designs vary, but their basic idea is this: so-called load-serving entities, for example distribution companies, hold periodic auctions to purchase the amount of capacity they deem necessary. Policy may also require them to purchase a certain amount of capacity sufficient to meet normal peak demand, plus a reserve margin. At periodic auctions, generation investors bid for capacity payments that supplement revenues from the energy market.[38] The bidders requiring the lowest capacity payments win.

Alternatively, capacity payments may be set by regulators as in the design coming out of Chile. There, capacity payments to all plants reflect the fixed cost of peaker plants. That way peaker plants can cover their fixed costs. All other plants can cover theirs as well, as the energy spot market provides some contribution to fixed costs for generators with marginal costs below the peaker plant. Together with the fixed cost of a peaker, this mimics remuneration for optimal capacity levels in energy-only markets.

Capacity mechanisms have features resembling PPAs for IPPs. Capacity payments cover a good part of fixed costs, and revenue from the energy market covers the rest. In capacity markets investors no longer take the risk of deciding how much capacity is needed. Capacity payments may be set in auctions for just a few months or multiple years.

Additionally, capacity markets may be technology neutral or split into markets for different technologies and locations. Regulators of some type make and administer these rules. This may introduce more political decision-making in the investment process. Some favor coal, others wind. Market signals may not guide the decision.[39]

Mandatory, Long-Term Contracts

Several countries in Latin America are hydro-dominated, which increases the need for long-term capacity payments. Long-term contracts between generators and buyers of electricity are often in place to ensure generation adequacy. Mandated contracts may extend as long as 15 to 20 years. Buyers are obliged to auction off contracts for, say, 100 percent of their expected peak demand plus a reserve margin. Generators or suppliers receiving such contracts are obliged to provide evidence of the corresponding physical installed capacity. Capacity payment mechanisms pay generation unit owners for their firm capacity. In practice, these markets must be carefully designed. For instance, generators may have limited incentives to make these units available to the short-term market, particularly if the supplier owns a portfolio of generation units (Wolak 2021a). Some markets, such as Colombia, have attempted to address this incentive by building implicit performance penalties into the capacity payment mechanism.

Noncompliance with the contract attracts a penalty. In efficient designs, contracting parties that fail to perform are obliged to honor their promises by making up for them in the spot market. For example, a generator that underdelivers would need to buy the missing amount in the spot market and provide it to the customer at terms agreed in the long-term contract. A distributor that consumes less than contracted would honor the contract and then sell the excess in the spot market.

Detailed designs vary. There are at least three basic schemes,[40] outlined below.

LONG-TERM CAPACITY CONTRACTS

Bidders for long-term contracts expect to be paid the price for energy, which reflects prices set by a cost-based, administered merit-order dispatch. They bid on a capacity payment[41] that—together with quasi rents earned from energy charges—covers fixed costs. This system, in principle, leads to an optimal mix of plants (e.g., baseload and peakers). In an efficient bidding system, the capacity charge would be the same for all controllable technologies. The basic logic is essentially the same as in long-term capacity markets. A variant of this is used in Brazil for thermal power plants.

LONG-TERM ENERGY CONTRACTS

Bidders for long-term contracts bid on a fixed (indexed) energy charge. Generators bid to supply a share of all the energy to be contracted over, say, 20 years as in Chile, and are chosen on the basis of the lowest price. Generators may produce some or all of the energy themselves or buy from the market to meet the overall energy goal. At the margin they are exposed to spot prices as under a CfD.

If only one company had to supply everything it would have an incentive to choose the least-cost mix of generation. The system splits that hypothetical monopoly into competing shares. In the aggregate, generators have an incentive to offer the least-cost solution at the lowest price, that is, the least-cost mix of peak and baseload that provides assurance that demand can always be met (see Wolak 2021b for the mechanics of the approach).[42]

RELIABILITY OPTIONS

This contracting system consists of creating a capacity market and mandating generators at the same time to issue "reliability options." Merit-order dispatch sets energy prices based on bidding by generators. The reliability option assures the buyer that the price of energy cannot rise above a predetermined strike price.[43]

In addition to this option, there can be voluntary forward contracts (e.g., CfDs) that may hedge energy prices below the level of the strike price of the option. Generators bid for contracts that promise to be available whenever needed, even at peak times—hence reliability options. In the auction they bid a price that jointly covers the missing money (like a capacity payment) and the cost of the option. When real-time energy spot prices are tightly capped, capacity payments for the missing money are high. When energy prices are subject to a higher cap, the payment for the missing money drops, but the option to insure against price spikes becomes more valuable, offsetting the fall in capacity payments.

At the extreme, if policymakers wanted to move to an energy-only market, the price cap (scarcity price) could be set at the VOLL. The implied capacity payment would be zero. The option would still assure buyers that prices cannot exceed the strike price. Variants of this scheme have been introduced in Colombia and the PJM market in the United States. The reliability option approach allows regulators flexibility to vary the price cap (scarcity price) while preserving the price hedges for consumers and generators and leaving generators exposed to bid-based market prices in the spot market at the margin.[44]

Ancillary Services

The basic market design elements discussed above form the core of market design, but they are not sufficient to assure a balance of supply and demand second by second and protection against system collapse. So-called ancillary services need to be at the disposal of the system operator to manage the quality and stability of the power supply. They include "regulation" and "contingency" reserves used for frequency and voltage control and services required to prevent system collapse. Regulation reserves are meant to provide a very fast response to frequency imbalances. Contingency reserves are reserves that take several tens of minutes to become available.[45] Traditional power system management protocols tend to drive the way ancillary services are deployed by system operators.

Regulation and Contingency Reserves

Several markets in the United States, Australia, and soon the Philippines, are run every five minutes. Yet, systems need to be balanced in shorter intervals—less than a minute. In the dispatch interval between two runs of the market, generators may have problems delivering or demand may change unexpectedly. To cope with this, system operators buy standby services—what in Australia is called “raise” or “lower” services—generators or demand resources that the system operator (SO) can utilize to balance the system. In Australia, these are procured at auctions every five minutes concurrent with the main energy market. Generators can thus decide whether to bid for being dispatched or to provide standby services. Such standby service auctions would no longer be needed if markets were run almost continually in real time, but that is not the current reality.

Different types of generators providing regulation or contingency services have different ramp rates, or inertia. They thus provide differing qualities of service for balancing purposes. For example, European markets distinguish between primary, secondary, and tertiary reserves. Primary ones need to respond within 15 seconds, secondary ones within 30 seconds, and tertiary ones within 15 minutes. There is thus a value in having different submarkets for regulation and contingency reserves reflecting their quality.

The introduction of intermittent renewables (solar and wind) increases the need for a fast response on an ever-larger scale. Solar and wind have next to no inertia. When the wind starts blowing or the sun comes out from behind the clouds, controllable generators need to ramp down almost immediately and vice versa when the wind or sun disappear. Special submarkets for very fast response generation thus make more and more sense. Hydro reservoirs and above all batteries excel in providing fast response.

System Stability

System operators, in addition, need to provide a public good: system stability. They may, for example, need to call on system elements, such as capacitors and inductors, to control so-called reactive power—the power that performs no work. This may be necessary to prevent voltage phase differences leading to a system collapse. Or they may need to call on certain generators to offset sudden outages or surges in demand to avoid cascading collapses.

As long as the system is stable, prices reflect the costs and benefits from dispatching the best generators. When the system collapses, there is no more price for electricity. There is thus no price established in the market that could remunerate the services that ensure the existence of the market in the first place. The provision of such services may be contracted out competitively—a form of competition for the market. Levies on participants in the electricity market typically cover the cost of such services. Levies may be implicit. For example, system operators may be able to direct generators to provide services without payment. It thus becomes a cost of doing business for market participants that ultimately is paid for by end users.

Procurement of Ancillary Services and Co-Optimization

Generators receive payments not only for energy or capacity provision but also for ancillary services. Investors need to evaluate all payment streams together to make their decisions. Ancillary services can be procured in different ways. They may be purchased through an auction for standby services or through negotiated deals. The traditional option is to purchase ancillary services independently of the energy market, for example, so-called strategic reserves that are on standby at the system operator's disposal. Ancillary services are ultimately paid for by customers through some type of levy. Yet, for regulation and contingency services, the auction should ideally allow co-optimization with decisions made in the market for energy. For example, by auctioning off contracts for standby capacity simultaneously with auctions for energy as in the Australian case mentioned above.

The existence of generation capacity that is paid for by out-of-market purchases gives rise to worries that system operators may at times deploy such generators in ways that depress energy prices and reduce revenues for investors, thus undermining the very essence of the energy market (Joskow 2006). As long as investors can foresee this adequately, it may not matter. Yet, it does add a layer of uncertainty. To reduce such uncertainty, rules have been introduced: for example, to require strategic reserves to bid into an energy-only market only at the VOLL.[46]

Remedies for the Abuse of Market Power

Electricity markets may be plagued by the exercise of market power. The key feasible remedies are as follows:

- There must be a significant number of competing generators. Large markets feature hundreds of plants. A sufficient number of these plants need to be independently run. Anything less than four independent players invites serious issues. Hence, it may be advisable to horizontally unbundle generation companies to create more of them, as done in Argentina before the market was introduced in 1992; deploy merger controls to prevent large players from being created; and make market entry for new investors as easy as possible.
- Hedges like CfDs reduce the incentive to exercise market power, because they require generators exercising market power to compensate consumers for it. Hedges are most likely to be used extensively in markets with scarcity pricing.
- Limiting price spikes via operating reserve pricing or capacity markets can reduce the incentive to exercise market power, but may also undermine the development of liquid hedging markets.
- Building out transmission systems to limit instances of congestion can help contain the emergence of load pockets, where some generator may be able to exercise market power, but this will also lower congestion rents and may lead to overcapacity.

- Because ex post, antitrust-style action against companies exerting market power is very hard,[47] several systems use audited cost estimates to cap the possible bids of generators that are suspected of being able to exercise market power at certain times (Cramton 2017). Most systems in Latin America only allow cost-based energy prices at all times.
- Developing real-time demand response in a smart grid could help a lot. Demand would become more responsive to price. When prices rise, demand would be cut back. Companies exercising monopoly power might be able to raise the price but lose significant volume, thus limiting the incentive to exercise market power. Exposure of demand to true scarcity prices would be needed to make demand fully responsive to system conditions.

The basic remedies for market power problems are thus tied up with the design principles for markets.

Markets, Climate Change, and Energy Transformation

The electricity sector is going through a rapid transformation, facing pressure to swiftly adapt to climate-change. From one side, the energy transformation results from growing appreciation of urgently needed actions to decarbonize the sector—reflected in government actions, such as renewable energy policies and decarbonization targets. From another side, energy transformation results from fast-paced technological innovations both on the supply and demand sides, leading to rapid adoption of new solutions.

Large shares of variable renewable generation are necessary in any decarbonized electricity system and this require adaptation to increased levels of variability and uncertainty. A decade-long experience globally has proven that a low-carbon power transformation is technically feasible. Whether this transformation can actually be delivered now largely depends on a suitable market design and regulatory frameworks. To incentivize these changes, markets must adapt and may need to be complemented by regulations.

While developing countries face serious challenges in their power sectors, they can invest in more flexible assets as part of overall expansion or replacement plans, thus creating an opportunity to leap-frog directly to a better-adapted system (IEA 2014).

As markets in Europe, parts of the United States, and Australia have demonstrated, although it is possible to attract flexible generation through appropriate capacity and balancing markets, much work remains. Several areas of market design need to be considered to ensure power systems are best adapted to the decarbonized systems of the future. While the search for the best market and regulatory instruments is still ongoing, the following aspects need to be considered while designing the markets.

Controlling Emissions and Carbon Pricing

Greenhouse gas emissions, for example carbon dioxide (CO_2) emissions, constitute an externality—a cost in this case—that is not automatically priced in the market. Carbon pricing can be an efficient approach to internalizing the climate externality and can be established in various ways.

The subsidy involved in feed-in tariffs is one method that aims at recognizing the climate benefits of renewable, intermittent energy. However, feed-in tariffs are a blunt way of pricing the externality because the tariffs are administratively determined and may not reflect the true cost of carbon. Some projects based on feed-in tariffs save emissions at low cost, others at high cost. In Germany, the implicit price paid for per ton of CO_2 reduction by solar and wind plants ranges from about \$50/ ton to \$500–\$900/ ton. Feed-in tariffs can thus generate unnecessary waste (Marcantonini 2014).

An alternative mechanism has become popular in US electricity markets: renewable portfolio standards. They require power systems to produce a certain share of power with clean energy such as solar or wind. This creates some scope for utilities to choose the most cost-effective solutions to meet the target. Yet, different portfolio standard still imply differing implicit prices per ton of CO_2 across areas.

Mechanisms to reduce emissions at lowest cost would confront power producers (and all other emitters for that matter) with a single price per ton of carbon. This could be done through a tax on CO_2 or by issuing tradable permits to emit CO_2. The former method amounts to setting a price that will lead to some overall volume of reduction. The latter method fixes the maximum volume that can be emitted and then derives a price through trade in the market. Efficient, single-price schemes of this type may be politically controversial, but they can work. A number of countries run successful tradeable permit regimes, like the Emissions Trading Scheme in the European Union or the Regional Greenhouse Gas Initiative (RGGI) in the United States.

All approaches to control emissions—regulations, taxes/subsidies, and tradable permits—put a price on emissions, through penalties or taxes. They all require that emissions are well monitored such that taxes or penalties can be assessed and/or prices formed. They differ in the efficiency with which they achieve the ultimate goal: a targeted reduction in emissions. For now, political concerns have led to a plethora of partial solutions. In a number of cases, multiple tools are deployed, for example, portfolio standards and/or feed-in tariffs plus tradable CO_2 permits. One problem is that the solutions are partial and have limited overall effect. The other is that when multiple incentives are deployed, for each case only one is binding but the cost of administering concurrent schemes is incurred.

Regardless of which method of emission control is chosen, the explicit or implicit prices placed on emissions will be reflected in the bidding strategies of generators in the market. Markets can handle them all. Yet, some are more efficient than others. What is politically contentious is that any type of emission control will take jobs from workers in “dirty” occupations and leave investors in dirty legacy plants with stranded costs. Compensation can, in principle, be designed such that continued operation of dirty plants makes no economic sense, while providing some relief for those affected by loss of income. For example, pollution permits can be auctioned off and revenues used for compensation schemes.

Variable Renewable Energy and Battery Energy Storage

Concern about climate change and sometimes about energy security has prompted great interest in renewable forms of energy, particularly intermittent sources of power: wind and solar. In energy-only markets without any subsidy, renewables would need to rely only on revenue from energy sales. They would receive contributions to cover their fixed costs as any other plant. In an energy-only market, that will provide adequate signals to investors. Yet prices become more volatile—dropping to zero when intermittent renewables meet all demand (or even become negative, depending on the design of market remuneration) and jumping to high levels—during scarcity pricing.

Capacity markets are exploring whether and to what extent intermittent sources of energy should receive capacity payments. If they contribute at the time of peak demand, they should. If they do not contribute at peak times, they do not save on other capacity investment that is needed. They then need to be profitable even if they always receive the system price that is determined by the highest marginal cost plant. In energy-only markets intermittent sources that contribute energy at peak time automatically get scarcity prices. In capacity markets regulators make somewhat arbitrary decisions[48] on how much intermittent sources contribute at peak times.

Several countries—for example, Chile, Brazil, Colombia, and Mexico—tackle the issue by requiring intermittent renewables producers to supply firm energy as well. The introduction of intermittent energy brings new challenges for the management of power systems. When the sun does not shine, or the wind does not blow, traditional forms of generation may need to be deployed to rapidly ramp up. This also means the mix of traditional generation needs to change to plants with fast ramp rates (e.g., natural gas and/or hydropower).

In practice and in the absence of meaningful carbon prices, intermittent renewable sources of power have mostly been promoted by some form of industrial policy, for example, through special feed-in tariffs or renewable portfolio standards. Each approach can be made compatible with the markets. Consider, for example, feed-in tariffs. They may be set by some regulator or established at an auction. Such feed-in tariffs can be made compatible with energy markets.

Solar and wind producers may bid in an energy market. They usually get dispatched, because their variable cost is essentially zero.[49] The difference between the price obtained in the market and the feed-in tariff is then paid out to investors as a subsidy, as in Germany and the United Kingdom. Alternatively, some type of portfolio standard or other regulatory requirement may be used. The penalty for not meeting it increases the relative variable cost of energy sources competing with those promoted by a standard or regulation, and thus affects bids in the market. Favorable tax treatment of renewables is another way to lower their relative cost and thus penalize other forms of energy.

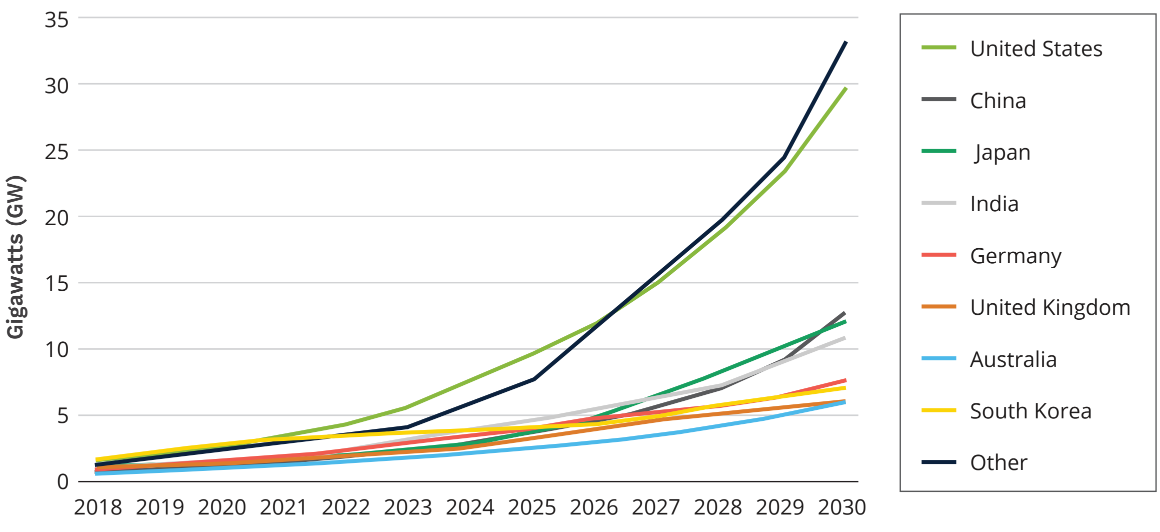
Another important technology to provide system flexibility with instant ramp rates is battery energy storage (BES). Interest in battery storage is rapidly expanding around the world, facilitated by rapidly falling prices for this technology. Subsequently, storage markets are developing much faster than anticipated (see figure 4.3) although the uptake of BES is only starting to take off. Storage solutions are an integral part of energy systems. They add flexibility and stability to the grid, particularly in countries with more mature energy sectors.

Batteries can enhance the value of intermittent renewables. They can store surplus renewable energy and make it available when it displaces the highest cost alternative. They also provide very rapid ramping capability, which renders them valuable for ancillary service provision. So far, due to cost and capacity limits, batteries can play only a limited role; but as costs decrease, they may become more widespread.

In principle, batteries can be integrated into electricity markets like other types of energy-limited generation, for example, pumped hydropower. They store energy when prices are low and sell when they are high. Investors will cover the fixed costs of batteries from that price difference. In this way market prices provide efficient signals for investment in batteries in energy-only markets. In capacity markets batteries would benefit from capacity payments as it is generally optimal to use energy from batteries when the opportunity cost is highest, that is, when system capacity is short.

FIGURE 4.3

Cumulative Storage Deployment by Country, Projections 2018–30



Source: Bloomberg Energy Finance as cited in Deloitte 2017.

Distributed Energy Resources: Distributed Generation

Standby generation to cope with power outages has traditionally been widespread in poor economies, mostly in the form of controllable, diesel-powered generators. A multitude of dispersed generation sources—from diesel generators to rooftop solar to electric batteries—constitute a form of distributed generation. Optimally for such standby generation, diesel generators have low fixed costs (the cost of "insurance" against power outages) and high variable costs.

As the cost of energy and digital technology lowers, distributed generation is also becoming a favorable energy alternative in countries where access to grid-connected electricity is difficult. In developed markets such low-fixed-cost and high-variable-cost generators may also be used to cope with power outages. Faced with unreliable power, larger firms may also provide their own regular power via captive generation, often without the option to sell surplus power to the grid.

Nowadays, decentralization is being quickly adopted in developed systems too. Households or businesses may install their own intermittent source of energy such as rooftop solar, recently also combined with battery storage. Several data analyses (e.g., Navigant 2018) show that new distributed energy resource (DER) capacity additions are already outpacing deployment of new centralized generation capacity. Forecasts see the proliferation of DERs and distributed generation, in particular at the global level, in the next 10 years. Both intermittent energy from renewables and batteries are high-fixed-cost and low-variable-cost sources of supply. Relatively more fixed-cost sources of generation should ideally feed into the grid, not just during emergencies but also during normal times. For intermittent sources of energy in particular, customers depend on the grid at times that the sun and wind do not provide energy. When they do, customers use their own power instead of that from the grid, and they may have the option of selling surplus power to the grid. This creates a wide range of new business models and regulatory approaches. For instance, Colombia is exploring new ways of restructuring its retail market, including the possibility of introducing nodal pricing at the level of distribution. The intent is to enable more vibrant customer participation, aggregation, and new forms of market activity.

A practical question is what customers should pay for the power they buy from the grid, and how much they get paid for the power they sell to the grid. For market design, another question arises: how can distributed generation most efficiently be integrated in the market? Captive power plants for large firms could have direct access to wholesale markets as part of competing generation sources. The value of distributed generation depends on the cost and reliability of the grid, tariff and subsidy design, and the existence—as well as sophistication—of both wholesale and retail competition. Smaller customers with new forms of home generation (prosumers) are harder to integrate into markets optimally. In some developing countries, the rapid growth of rooftop solar is making it challenging to manage a distribution grid not meant for bidirectional flows—as in Vietnam, where 9.3 GW of rooftop solar capacity was added in the month of December 2020 in response to a feed-in tariff policy, surpassing the target of 12.5 GW by 2023.

Distributed Energy Resources: Demand Response

Real-time demand response holds promise to minimize capacity needs in any market. It can be particularly helpful to dampen price fluctuations necessitated by intermittent energy sources. Generally, it is becoming more practical and cost-effective to allow customers to respond to electricity prices in real time. Large consumers already respond to prices by participating directly in wholesale electricity markets. They buy their expected consumption in advance and respond to price variations by reselling on the short-term markets. In addition, smart meters and progress in automation technologies increasingly enable even smaller consumers and households to be price responsive, either directly or through third-party aggregators. Dynamic pricing options, such as critical peak pricing, are a straightforward way to tap into this potential.

Alternatively, customers can delegate parts of demand management to system operators. The latter have more and more technical options to adjust the electricity use of customers, such as the use of heating and air-conditioning systems. Much of the demand response may be preprogrammed and facilitated by the "internet of things," where all sorts of sensors and measuring devices provide the underlying data and communicate them to relevant decision-makers. This option treats demand response as generation, and dispatches it on wholesale electricity markets. Direct participation of demand response aggregators in capacity markets has been effective in kick-starting demand response in several markets, such as the US regional transmission organization PJM.

Market design will need to allow pass-through of real-time prices to final customers. This would include exposing "retailers" or "aggregators" of final demand to real-time prices. Such aggregators have an incentive to offer final customers more attractive price plans in return for customers' physical response to real-time prices. For instance, in 2017, Brazil introduced both time-of-use tariffs and an incentive-driven demand response program to elicit demand response from low-, medium- and high-voltage consumers, aiming to reduce and time-shift demand load from (previously authorized) consumers—not necessarily only large—to displace thermal generation in the centralized merit order.

The move toward real-time price response would be facilitated by introducing competition-based nodal pricing at the transmission or wholesale level as well as in distribution systems. In theory this is possible, but not yet practical. For now, distribution system operators may pursue options to monitor and control demand in more refined ways, yet still falling short of nodal pricing. This at least allows more options to respond in real time to efficient prices at the nodes of the transmission system. As markets feature more players and allow demand response, it becomes more and more important to allow prices to emerge based on bidding and to use prices for energy to generate a greater share of revenue.

FIVE
UNDERTAKING REFORM

Reform Process: Market Objectives and Country Context

Objectives, institutional capacity, social acceptance of price fluctuations, and the risk appetite of policymakers vary across countries, signifying that market design should adapt to local conditions and balance them to achieve desired outcomes. Clearly outlining what is desired from introducing electricity markets is especially important in this process, and the trade-offs between design options need to be properly weighed. An appropriate market design for developing countries needs to be viewed in the overall context of institutional capacity, market structure, social acceptability of fluctuating prices, and many competing objectives, be it greater effectiveness in bringing needed generation supply (especially VRE) or the increased efficiency of certain system areas.

Key Design Options

The market design principles discussed so far do not suggest a single best model. Several core options are summarized as follows:

- Should prices used to optimize operational dispatch be based on bids or based on the audited costs of generators; that is, should it be a bid- or cost-based market?
- Should transmission constraints be reflected in prices that may differ at each node of the system, or should there be some form of uniform pricing? That is: nodal or zonal pricing system?
- Should fixed costs be recovered only from revenue generated from prices for energy actually delivered, or should fixed costs be covered at least in part through regular special payments for capacity? That is: an energy-only market or with the addition of the capacity market?
- Should long-term contracts between buyers and sellers of electricity be voluntary or mandated?

In practice, there are many additional design elements. The market rules, or the grid code, can easily run to hundreds or thousands of pages. Each market has its own quirks. Sometimes design features are ill-conceived or have unintended side effects. Hence, ongoing review and adjustment of market rules is common. This requires an adequate governance framework for rulemaking and enforcement in the light of experience.[50]

Deciding how to respond to above questions in designing the market should depend on the context of the specific system and policy objectives. For example, the experience so far suggests that markets with fewer barriers to time- and space-varying price signals, resulting in higher price fluctuations and experiencing scarcity pricing more often to remunerate relevant generation, effectively manage the systems. This is especially true with increased amount of intermittent renewable electricity generation. It may, however, conflict with a government's objective of flattening price changes. As another example, a nodal pricing system provides stronger signals for congestion management and reflects network conditions in real time, evidenced by PJM-like markets. Yet the governments of EU countries and many developing countries will find it difficult to accept differing prices within their national borders, although there are established mechanisms to manage this.[51]

Developing economies with relatively small power systems may be particularly concerned about abuse of market power and it may provide a rationale for, initially, going for a cost-based market design driving dispatch. These examples of regulatory constraints reflect the multiplicity of country contexts and regulatory objectives that may range from minimization of electricity costs in one country to promotion of renewable supply in another to ensuring equity and basic access in a third.

Importantly, developing economies may want to provide extra comfort to investors to make sure growing demand for electricity can be met. Many markets in developed countries are designed for saturated systems with flat, or even contracting, demand, while developing countries tend to experience rapid demand growth that prioritizes financing rapid growth of investments in generation. Concerns about access and investment favor designs that make investor revenue reasonably predictable, while maintaining some degree of market discipline by use of auctions. This reinforces the argument for some type of capacity remuneration mechanism, whether a capacity market or mandatory long-term hedges. A liquid market for long-term contracts of some type may be of particular value for countries with a potential for cost-effective, large hydropower plants and may be overall well suited for larger shares of intermittent renewables. When investors can credibly expect revenues to remunerate capacity, they are likely to consider long-gestation projects—including hydropower and nuclear facilities. At the same time, such capacity remuneration mechanisms can, in principle, be designed in a technology-neutral fashion by placing all types of investors on an equal footing.

Small power systems in developing countries may be too small for electricity markets to be practicable (Besant-Jones 2006). As many as 32 countries in Africa have an installed capacity of under 1 GW based on IEA data for 2016. Regional electricity markets may provide an important and feasible option to optimize their power costs, protect against fuel price shocks, and relief in cases of generation shortfall (Olmos and Pérez-Arriaga 2013; Oseni and Pollitt 2014). Countries with small power systems stand to gain the most from additional transmission interconnections to create economies of scale and enhance their energy security, but that will be true for larger systems as well in the context of geographically varied energy resources.

For markets to work well, investors have to believe that the market rules are sustainable and will not be capriciously adjusted. This implies that a key concern is the underlying politics of pricing and revenue generation. For example, energy-only markets require political tolerance for rare, drastic price spikes. Nodal pricing schemes require tolerance for prices that vary across locations within a country.

Reform Process: Checklist for Implementation

The following is a generic checklist of the steps of a market reform process, their possible sequence, and the relative complexity of the efforts involved in each step. It is intended to be a brief overview, since several activities merit separate, extensive discussions and full reports, possibly as a sequel to the current paper.

Step 1. Assessment of Prerequisites for Reform

Choosing when to introduce a wholesale market is critical to its success, yet the question of timing rarely gets the attention it warrants. The timing and structuring of reform affect whether it is possible to garner the necessary momentum and public support. The optimum timeline depends on a range of factors, as discussed below.

POLITICAL SUPPORT

The decision to embark on a policy reform to introduce a new market or strengthen an existing one requires political support. Such support may be driven by several factors, not all of which necessarily align with the principles of an electricity market. Nevertheless, it is important to understand the motives for supporting a market. This is best done up front, through a stakeholder consultation process. Understanding these motives will help prioritize the issues at hand, assess the sustainability risks, and tailor the market design to best align with key priorities and policy objectives.

GOVERNANCE CAPACITY

As wholesale electricity markets become increasingly sophisticated, they require a certain level of capacity among the ministry of power, the regulator, the system operator, and generation and distribution companies, as well as large customers, to ensure their efficient operations. This is a significant ask that calls for a comprehensive assessment of the capacity of all market participants and the wider set of stakeholders. There are inevitable gaps even in systems with good planning and regulatory practices in place, as market regulation, while not always greater, will require a different set of knowledge and skills. It is important to develop a gap analysis that will address resources and skills that will need to be plugged realistically over a period of time and to adapt the market design accordingly.

READINESS FOR MARKET-CENTRIC REFORM

In many cases, past reform processes often stopped at vertical unbundling and did not properly deal with important issues around transmission access, transmission pricing, high market concentration and associated market power issues, access to upstream fuel, legacy PPAs, and downstream tariff reform needed for distribution companies to have sufficient degrees of financial viability and capacity to participate in the market. Although these issues are well known, many markets have been designed without full attention to these details, remaining highly illiquid and hence not serving their purpose. These issues need to be identified up front, possibly through a white paper that clearly lays out the minimum policy reforms that must take place before a market of any kind can be introduced. It is important that the minimum level be articulated clearly, met in full, and reflected in the market design, with a provision for additional features to be introduced as concomitant reforms are put in place.

PHYSICAL PARAMETERS OF POWER SYSTEMS

The white paper could also assess feasibility of introducing a market in a particular power system considering its physical characteristics, including the system size, the nature and composition of generation sources (e.g., must-run generators), their fuel supply, and, therefore, the feasibility of having enough future market participants from the generation and demand side; availability of a sufficiently developed transmission grid; and the system monitoring, automation, and control equipment. Having these considerations in place may inform decisions about market design, whether joining a regional market is an option, or set a timeline for meeting these physical preconditions.

FINANCIAL HEALTH CHECK

A comprehensive financial assessment of all key players, especially the purchasing entities (including cross-border power imports), is a critical requirement. In a system with financially distressed distribution companies or inadequate financial products needed for spot price volatility risk management, a wholesale market can serve very little purpose and at times may even worsen the state of some of these entities. Payment discipline and the solvency of utilities, combined with the ability to deliver services and last-resort measures, must be ensured. A sector-level economic and financial analysis of the position of key players will help avoid meltdowns that have occurred in some markets.[52]

Step 2. Choice of Market Design

WHITE PAPER

As the preceding discussion demonstrates, a multitude of issues need to be considered when choosing a market design, the details of which will inevitably vary to suit specific circumstances, even if the general principles are the same and particular attributes resemble those of another market. These nuances are critical to the success of a market and need to be fully reflected on in a white paper building on the analysis of prerequisites.

A key principle to remember is that the details of market design can and should vary to fit the idiosyncrasies of each system while respecting basic design principles that drive efficient operation in the short term and provide the right investment signals in the longer term. It is also important to build an adequate degree of flexibility to adjust design parameters for the market to remain agile. De facto, designs are fine-tuned over the years—a process that the most advanced electricity markets continue to undertake even 25 years since they commenced, continually adapting to meet evolving policy objectives.

A major pitfall to be avoided is the propensity to copy a detailed market design from another system, even if there are certain advantages to it in the very short term. The white paper on market design needs to focus on the system at hand, outlining its current governance setup, regulatory capacity, financial state, technical know-how, and physical infrastructure. It may take some time to collect information and develop the white paper, but this is time well spent.

STAKEHOLDER CONSULTATION

Stakeholder consultation is an integral part of deciding the market design. The process needs to be extensive, with adequate representation from generators, buyers—including distribution companies—transmission system owners, system operators, the regulator, investors and financial institutions, a wide array of national and international experts, and customer representative bodies including civil society groups, and so on. The process needs to be conducted efficiently, with sufficient time budgeted, to ensure adequate consideration of all views and avoid the undue influence of one or more dominant stakeholders.

MARKET RULES

Market rules are the most critical components of any market. They are intended to be a living document that translates the Electricity Act into a set of rules describing how the act should be interpreted, the roles of concerned agencies, physical connection requirements, product definitions, how prices and quantities are to be determined, specific responsibilities and liabilities of market participants, market/system operation requirements, and settlement arrangements. There is great variation in their level of detail across countries and markets.

As the market design should be tailored to a particular system, the market rules also need to be system specific, and in all cases fully transparent in describing all relevant responsibilities (including the information to be disclosed by each participant), penalties for noncompliance, and so on. Sufficient time must be allotted for the full documentation of the initial set of rules. A change management process should be put in place to allow adjustments to the rules as needed, including changes reflecting feedback from the stakeholder consultation process.

REGULATORY AND REPORTING ARRANGEMENTS

A market regulator's role encompasses all aspects of the Electricity Act, ranging from market monitoring and dispute resolution to ensuring transmission and distribution cost recovery and charting a path for the evolution of the market. The introduction of a market can substantially stretch the role of a traditional regulator in a vertically integrated regime—a fact that is easily overlooked when setting up a market.

As power sectors in most countries are undergoing a transition with the introduction of renewable energy, an increasing level of sophistication on the technology front, and greater customer participation, the job of a market regulator is becoming increasingly complex. A regulator will typically need to continue many of its existing functions around tariff setting for retail customers and grid reliability, yet add several new functions and streamline others, especially around transmission and distribution regulation in a market environment, to ensure that the market operates efficiently and transparently.

Regulatory functions need to be articulated clearly, and sufficient capacity for new or modified functions ensured. The reporting requirements of market participants to the regulators and also the information these entities and the regulator itself need to publish routinely must be clearly defined. Empirically, there has been a surprising lack of oversight in some areas, including a lack of transparency on the fundamental market-clearing process, the level of information that the generators are required to furnish to the regulator and for public disclosure, the performance standard of generators and transmission asset owners, market monitoring, and so on. It is critical that these issues be fully settled at the outset to develop a credible marketplace.

A wealth of global lessons may be used to set up best practices in key areas and ensure the incumbent regulatory body has the necessary capacity to implement the minimum level of regulation needed. A comprehensive capacity-building effort may need to be embedded in this step to ensure the regulatory capacity is up to the requirements of the initial commencement of the market.

TRANSITION MECHANISM DESIGN

The design of this critical mechanism must account for key concerns that may need to be addressed during a market's early period of operation to avoid the risk of a major disruption. Such concerns include the financial hardship of a buyer or seller, legacy contract issues, the time needed to implement measures needed for the physical system, financial products needed to manage price volatility risks, and software for market clearing and settlement that may not be essential but can render the market more efficient. Transition mechanisms are by definition short-term and temporary measures. Since they are critical to a market's timely start and to minimize the risk associated with a new market, it is important that sufficient time be spent on designing the necessary mechanisms, consulting with key stakeholders to address their specific concerns, and ensuring that these are eventually addressed for the market to function properly.

Step 3. Market Commencement

INSTITUTIONAL ARRANGEMENTS

Significant efforts are needed to ensure the market starts on time with responsibilities allocated appropriately across agencies (including the regulator, the market/system operator, buyers and sellers, supporting information technology vendors, and consultants) and the necessary protocols in place. The timetable for a market start is often arbitrarily set well in advance without full recognition of the effort needed to develop relevant institutions to a fully functional level. Meanwhile, unforeseen delays discourage market participants and can destroy the credibility of the market even before it starts. The timetable needs to reflect reality and be conservative, accommodating potential delays.

TESTS AND PILOTS

Even a relatively small electricity market that trades 20 terawatt-hours (TWh) a year may trade around $1 billion within that time frame. The precision and transparency of the market-clearing process, including the software system that is used for market management and market clearing and settlement, physical connections for data transfers from/to all market participants, and so on, need to be thoroughly tested. An audit of these systems needs to be enshrined in the market rules and be followed rigorously. Even after the tests are conducted, there should be a pilot phase during which the market operates but the outcomes are not binding.

INITIAL PROBLEMS AND TROUBLESHOOTING

Even with the best of transition mechanisms, testing, and piloting programs in place, some pricing and settlement outcomes will typically require investigation and potential fixes. These could range from software glitches to data/communication failures and unpredictable outages in the physical systems, to participants' lack of understanding of pricing/settlement outcomes. It takes a dedicated team at all levels—the market/system operator, the regulator, and the ministry—to resolve these issues efficiently and build participants' faith in the system.

Endnotes

i. The terms competition "in the market" and "for the market" go back to an article by Edwin Chadwick from 1859. He used the terms "in the field" and "for the field" (Klein and Roger 1994).

1. Monopolies need not be state run, and competition may also involve state-owned companies. In practice, many electricity monopolies are state owned, and state-owned companies rarely compete with one another. Even if allowed, their incentive to perform is easily undermined by an implicit guarantee of their finances by the government—that is, the taxpayers.
2. During this time, researchers at the Massachusetts Institute of Technology and their collaborators set out to demonstrate that economic principles were actually compatible with the physics of electricity. Power does not always flow from low-priced nodes in a power grid to high-priced nodes. Instead, it spreads across the network, following the path of least resistance. However, competitive trading of electricity and market–based price formation was possible when explicitly considering the physical structure and constraints of the transmission system. Prices at every node (nodal prices or locational marginal prices) would reflect demand and supply conditions, taking into account congestion and transmission losses. Competitive trading would give consumers the best deal and remunerate producers for operating and investment costs. The results were famously summarized by Schweppe et al. (1988). In 1996, Order 888 by the Federal Energy Regulatory Commission created open access to transmission systems and the functional unbundling of utilities that enabled competition in the market.
3. The initiation of power market reform is dated for all countries in IFC (forthcoming).
4. Often, systems with competition in the market are subdivided into those with "wholesale" and those with "retail" competition. The difference is who has access to the market on the demand side—only large (wholesale) users or also smaller (retail) users—with somewhat arbitrary cut-offs of what qualifies as wholesale or retail.
5. Captive power plants and off-grid connections (mini grids) have become popular in recent times in developed markets as well as part of efforts to promote resilience and renewable energy sources, for example, rooftop solar.
6. Further attempts to assess the impact of broad power sector reforms are found in Nagayama (2010) and Erdoğdu (2014). The World Bank (2019) provides a review of experience with market design based on analyses of four countries: Colombia, India, Peru, and the Philippines.
7. The often-quoted threshold of "four competitors" is based on the view that collusive arrangements among more than four competitors are hard to reach and maintain. See, for example, Selten (1973).
8. For an illustration of the judgement required, consider Chile and Norway. Today, both countries feature power systems based on competition in the market that have withstood the test of time. When Chile started considering the first reform of its type in the late 1970s, few could foresee that the country would be ripe for a power market—given its checkered political history and a small system size of just over 2 GW. Equally,

Norway is a surprising player who, as a social democracy, successfully established a new type of market with many state-owned players in 1990. Interestingly, both countries implemented reforms amidst major macroeconomic crises.

9. Various degrees of unbundling are possible: accounting, functional, legal, and corporate unbundling (Hunt 2002). Some degree of unbundling may make sense even when there is no intent to introduce competition. It may simply help improve cost accounting and incentives within the monopoly and thus management.
10. Note that a system operator, market operator, and settlement administrator can be part of the same organization or separate.
11. In practice, it tends to be politically easier to unbundle previously state-owned systems.
12. Strictly speaking, monopolies need not be state run, and competition may also involve state-owned companies. In practice, many electricity monopolies are state owned, and state-owned companies rarely compete with one another. Even if allowed, their incentive to perform is easily undermined by an implicit guarantee of their finances by the government, that is, the taxpayers.
13. In large natural gas pipeline systems, more decisions can be decentralized as the US model demonstrates. Essentially, this is due to the ability to store natural gas flexibly and direct its flow in ways that are either not feasible or too expensive in electricity systems (Makholm 2017).
14. In practice, many markets feature mostly supply-side bidding. Demand is often accepted “as is,” except for some “interruptible” customers.
15. Part of the regulated revenue transmission operators receive may be from so-called “congestion rents” (see section on transmission pricing below).
16. The crucial debate about the independence of the system operator is set out in Joskow (2007b) and Hogan (1998).
17. System operators are responsible for the operation and control of the bulk power system to (1) meet load and security needs with real-time dispatch to balance supply and demand, (2) manage ancillary services, and (3) manage transmission congestions. Market operators focus on energy trading, scheduling, and settlement of energy transactions in different time horizons. Market surveillance administrators help in managing fair, efficient, and openly competitive operation of markets. Their mandate is to carry out surveillance and, when needed, investigation for the generation, transmission, distribution, trade, purchase, or sale of electricity, or ancillary services.
18. The fees themselves may be set by a regulator.
19. For example, New Zealand, the Scandinavian countries, and PJM in the United States provide options for demand-side bids. In practice, demand-side bidding is not found in all systems.
20. In stylized terms, the lowest marginal cost generators tend to be solar or wind power, followed by hydro and nuclear, then coal followed by gas, and finally diesel plants with the highest variable cost.
21. The lowest variable cost to the system may be established by bids or via audited cost data approved by some form of regulator.
22. Peter Cramton, an authority on electricity market design, has argued that by now advances in optimization models have rendered them more efficient than bilateral trading among market participants (Cramton 2017).

23. Several systems explicitly allow for that. For example, France and several other European systems allow negative price bids down to a floor of €500/MWh.
24. Where production tax credits are provided to renewables producers, they have an incentive to bid negative prices down to the value of the tax credit even though it would not be economic to dispatch renewables in this case. In some systems, for example in Germany, solar and wind have "grid priority": they must be dispatched in preference to other generators even if some other plant bids negative prices.
25. This is gradually changing. For example, in several US states, system operators can turn down air conditioners in anticipation of strains on system capacity. Households that choose to participate in such demand-side programs benefit from lower bills. Larger customers have for some time had the option to conclude "interruptible" service contracts at lower costs.
26. In practice, the WTP of the average customer subject to load shedding may be estimated.
27. This is a traditional standard in the United States (Stoft 2002).
28. Actual values of VOLL used in different systems vary. By way of example, in Australia's national electricity market the wholesale price cap for the time of load shedding was set at $14.70/kWh in financial year 2019/20. This compares to prices of say $0.3–$0.4/kWh at normal times. On the lower side, the Philippines featured a price cap of about $0.64/kWh in 2019.
29. To accommodate unexpected contingencies between runs of the real-time market, system operators deploy so-called ancillary services such that demand and supply match second by second.
30. Note that sometimes short-term, day-ahead markets are called spot markets, although strictly speaking they are not real-time spot markets, for example, the Scandinavian Nord Pool "Elspot" market.
31. It is as if there were one large marketplace and transport costs did not matter. However, transmission systems do have transport limits.
32. Even if just one line is congested, all nodal prices will differ but only two of them will be independent of each other. In general, if there are m congested lines, there are only $m+1$ independent prices.
33. For an exposition of the theory of nodal prices, see Biggar and Hesamzadeh (2014).
34. In the US natural gas system, it has proven possible to decentralize investment decisions in new pipelines. Also, trade of slices of capacity is possible—as of a pipeline containing a series of "straws" that one can buy or rent to transport gas. This is made possible by flexible options to store gas, for example, through a "line pack" and by using valves to direct the flow of natural gas (Makholm 2017). In Chile, some transmission lines that connect plants to the grid were financed by independent investors. These lines can be thought of as extensions of the plant. It is also possible to allow independent investors to build DC interconnectors between two AC systems. Power flow on DC lines can be controlled and investors can assess congestion rents (Biggar and Hesamzadeh 2014).
35. This is a general point. For example, it makes no economic sense to build out road systems such that congestion never occurs. The benefits of reducing travel time a little will be less than the cost of building and maintaining the extra road space.

36. Base load plants have high fixed costs for availability and low marginal costs for the provision of energy. In a system with an optimal mix of plants, they run all or most of the time and thus have the lowest levelized cost of electricity or revenue requirement per unit of output. Peaker plants have low fixed (availability) costs but high variable (energy) costs. They run only for short periods of time and have the highest levelized cost of electricity.
37. In cost-based spot markets, the cap is equal to the highest marginal cost allowed.
38. The Chilean market design features a regulated capacity payment.
39. In energy-only markets regulators set the price cap that corresponds to a volume of capacity. Here market forces are constrained by a regulatory fiat, yet in a technology- and locational-neutral fashion.
40. The discussion lays out the basic logic of these schemes and omits more detailed features. For example, in Chile, bidding for long-term contracts is broken down by blocks reflecting time of day or season. The characterization of the Chilean and Brazilian market is based on communication received from Alexander Galetovic at the Universidad Adolfo Ibanez in Chile. The principles behind the Colombian approach are based on Cramton, Ockenfels, and Stoft (2013) and Rudnick and Velásquez (2019b).
41. The Brazilian capacity payments are denominated in reais/MWh. This is a fixed hourly payment per capacity of one megawatt independent of whether the plant has been dispatched and has sold energy.
42. A variant of this approach exists in Chile. There, bidders expect to be paid an administratively set capacity payment based on the fixed costs of a peaker plant. Bidding is for the energy price that covers the payment for both the variable cost of energy and the contribution to capacity remuneration from the energy market.
43. In Colombia today, the energy price is capped (scarcity price) at the highest marginal cost. In the past, the proxy used to set this price has not always reflected the effective marginal cost in Colombia.
44. The following three cases illustrate the way the system works, in principle. *Case 1:* When the price cap in the energy market equals the highest marginal cost of generators and in turn equals the strike price, then load never pays energy prices above the marginal cost. The amount generators seek at auctions is equivalent to a capacity charge. *Case 2:* When the cap is at VOLL, load pays more than the strike price when there is a scarcity event. At the same time, the strike price may still equal the highest marginal cost. In this case generators obtain enough revenue in the energy market to cover fixed and variable costs, but they have to compensate load for any price higher than the highest marginal cost. This is equal to the missing money or the capacity charge in case 1. So, generators seek the same amount as in case 1. *Case 3*: The price cap may be below the VOLL and the strike price above the highest marginal cost. There is then some missing money in the energy market and a cost to fulfill the reliability option. The sum of these two items is, in principle, the same as in cases 1 and 2. Hence, generators seek the same amount at auction regardless of the combination of the price cap and strike price.
45. Note that terminology and implementation details vary across systems.

46. In Australia, for example, some generators providing “security services” that have been paid for through out-of-market purchases may only be allowed to bid into the market at the VOLL. This way they will only be dispatched when the system absolutely needs them.
47. See Biggar and Hesamzadeh (2014) for a discussion of the challenges.
48. Optimization program can be used to approximate how much intermittent renewables should benefit from capacity payments, by estimating their “effective load carrying capacity.” This is a challenging task, especially for generation plants whose outputs depend on externalities, such as hydropower plants where the amount of available (or “firm”) capacity will depend on the quality and accuracy of hydrological conditions.
49. In some systems, Germany for example, solar and wind have “grid priority”: that is, they have to be dispatched in preference to other generators even if some other plant bids negative prices.
50. A review of market design issues in countries of the Organisation for Economic Cooperation and Development is found in IEA (2016).
51. Most markets with nodal pricing address this challenge by simply charging final customers a weighted average of the pricing for the whole zone (that can be a country or region).
52. A World Bank study published in 2020 analyzed 15 case studies comparing cost-recovery rates pre- and post-reform across developing countries. The study found that electricity tariffs are rarely high enough to ensure cost recovery and although the level of recovery has generally improved over the years, there is significant variability across the cases with as many as half the cases showing a decline in the postreform period. The study presents an excellent conceptual framework that can be adopted to underpin the sector-level economic/financial analysis needed as part of a reform (see Huenteler et al. 2020).

Glossary

Ancillary services: Technical services necessary to ensure reliable power supply and a reliable operation of a power system (i.e., necessary for frequency, voltage, and power load to remain within certain agreed limits). Ancillary services usually include four broad services: frequency measure (e.g., spinning reserves, balancing); voltage compensation (e.g., power factor correction); supply reconstruction (e.g., black start); and operational management (e.g., grid monitoring, redispatch).

Balancing market: A balancing mechanism that is based on market principles (i.e., bids and offers from the supplier of balancing services).

Balancing services: A set of various, reactive, short-term means, techniques and mechanisms used by a System Operator to ensure that there are no frequency deviations in the power grid (that is supply and demand are equal over a certain time period).

Capacity market: a sub-market in some wholesale electricity markets to pay generation resources with a previously agreed-upon price for being available to produce electricity at future date when needed, ensuring reliability. Capacity is not actual delivered electricity, but rather the ability to produce electricity when called upon.

Congestion: Congestion occurs when a transmission line (or lines) reaches its maximum carrying capacity. When this occurs, the regions on either side of the constraint are considered 'islands' in price terms. One island cannot supply any more electricity to the other, meaning demand has to be met by local generation plants.

Congestion rent: Congestion rents or merchandise surplus are the difference between payments made by locational loads and the revenue received by generators at the time of transmission congestion. In the absence of congestion, all locational marginal prices would be equal and congestion rents would be zero. Theoretically, an optimally built-out transmission network generates a congestion rent that covers the full cost of the transmission system.

Contingency reserves: Reserve that are sufficient to cover the unplanned outage (disconnect) of a large generator or transmission line and maintain system balance without cascading outages, loss of demand or curtailed firm transfers, system instability, or exceeded voltage or thermal limits. Contingency reserves are generally split between synchronous (spinning) and non-synchronous (non-spinning) reserves.

Contract for Differences (CfD): A financial contract, in which the seller agrees to sell a specified quantity of electricity forward at a specified price to a customer during a specified period. When spot prices diverge from the contracted price the party benefitting from the price difference compensates the other for the price difference applied to the forward contract.

Co-optimization: In contrast to a traditional system, in which ancillary service dispatch is determined sequentially (either before or after energy dispatch), in a co-optimized system, the system operator determines simultaneously what combination of energy and ancillary services the generator should supply each hour to minimize total power system costs.

Cost-based market: A market where generators submit their marginal costs data, which the system operator can audit, and based on which the generators are dispatched.

Day-ahead market: A market that helps system operators prepare for a daily dispatch and is operated through an auction which takes place the day before dispatch all year round. All hours of the following day are traded in this auction.

Decarbonization: Zero net emissions of CO_2, as well as the stabilization of emissions of short-lived greenhouse gases such as methane that dissipate in the atmosphere.

Economic dispatch: The economic dispatch process is short-term determination of the optimal output (merit order) from the generating plants needed to meet the system load, at the lowest possible cost, subject to transmission and operational constraints.

Distributed Energy Resources (DER): Small-scale power generation, storage or demand response resources located close to where electricity is used (e.g., a home or business). DER systems may be connected to the local electric power grid or isolated from the grid in stand-alone applications. DER systems can be used by consumers to manage energy bills and ensure reliable power by augmenting a consumer's current energy services or to operate independently of the electricity grid.

Energy market: Sometimes referred to as power exchange, an energy or electricity market is a system enabling the purchase and sale of electricity as a commodity. Electricity can be bought, sold, and traded in wholesale and retail markets.

Energy-only market: Whereas capacity markets aim to ensure grid reliability by paying participants to commit generation for delivery years into the future, energy-only markets pay generators only when they actually sell power.

Financial Transmission Rights (FTRs): A contract that entitles the holder to receive or pay compensation for transmission charges that arise when grid congestion causes price differences between nodes.

Forward market: The market segment in which electricity is traded for future periods. Typical delivery times can range from days to months or even years in the future.

Gross pool: A market where the clearing price reflects full demand and supply, even if some of the demand or supply is settled outside of the market.

Imbalances: Differences between real time production and consumption volumes.

Independent Power Producer (IPP): Non-utility generators that are typically not owned by the national electricity company or public utility, and which generate electricity for sale to the national electricity network. IPPs can also sell power to a single, third-party via customer via a power purchase agreement (PPA). IPPs may use the national electricity networks distribution system if mechanisms exist to permit this or via a private wire direct to the customer.

Independent System Operator (ISO): The entity that operates the transmission system in real time and is tasked with ensuring non-discriminatory access to the grid for individual generators.

Intraday market: A market that settles /determines the price for one-hour periods or less during the day of delivery.

Load shedding: The reduction of system demands by systematically and in a predetermined sequence interrupting the load flow to major customers and/ or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations.

Locational marginal prices (also nodal pricing): The market-clearing price for electricity at the location the energy is delivered or received, reflecting congestion.

Market power: The ability of any market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability.

Net pool: A market in which participants in the real time market bid only to cover imbalances between contracted amounts and requirements in real time.

Open access: The requirement for utilities to allow market participants to use their transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis (for a fee).

Pay-as-bid: An auction in which prices paid to winning suppliers are based on their actual bids, rather than the bid of the highest priced supplier selected to provide supply (as in uniform-price auction).

Power pool: An association of energy utilities that coordinate their operations (aggregation of power from various generators, arranging exchanges between generators, and establishing or enforcing the rules of conduct for wholesale transactions) to maximize system stability and achieve least-cost dispatch. The pool may own, manage and/or operate the transmission lines, or be an independent entity that manages transactions among others.

Power Purchase Agreement (PPA): A contract between one party that generates electricity (seller) and a party (usually a distribution utility) who purchases the electricity (buyer). The terms and conditions (starting date, duration, price or payment arrangements, delivery point, and performance terms) are specified in the contract. The contract (agreement) allocates the risk between buyer and seller for respective nonperformance.

Demand response: Demand response compensates end-use (retail) customers for reducing their electricity use (load), in response to signals from the system operator, during periods of high prices, or when the reliability of the grid is threatened. This load reduction can come from shutting off machinery, adjusting a thermostat setting, turning on a generator, or switching on a battery.

Renewable Portfolio Standards (RPS): Sometimes referred as renewable electricity standard, RPS is a regulatory mandate to reach a target of energy production from renewable sources such as wind, solar, biomass, and other alternatives to fossil and nuclear electric generation.

Retail competition: Competition gives retail consumers choices as to how to satisfy their power needs, either through the incumbent utility, competitive retail suppliers or, in some instances, directly from the generators or the wholesale market.

Single buyer: An often publicly owned entity that purchases some or all of the electricity from independent generators and sells to customers.

Spot market: A term variably used to refer to markets for day-ahead or real-time electricity.

Stranded costs: Costs that cannot be recovered due to unexpected policy regime change such as the introduction of competition or new environmental regulations. Stranded costs are calculated as the difference between sunk costs and the present value of expected operating earnings from those sunken assets.

Unbundling: Disaggregating components of a previously integrated power company. Separating electricity service into its basic components (generation, transmission distribution, and retail) and offering each component for sale is usually referred to as vertical unbundling. When generation companies control large market shares, horizontal unbundling may be necessary to create a critical mass of competitors and prevent reconcentration via mergers and acquisitions.

Variable Renewable Energy (VRE): Renewable energy sources that are not controllable, such as wind power and solar power, as opposed to controllable renewable energy sources, such as dammed hydroelectricity or biomass, or relatively constant sources, such as geothermal power.

Vertically integrated monopoly: One utility owns and controls all levels of the supply chain (generation, transmission, distribution, and supply), serving a defined consumer territory.

Value of Lost Load (VOLL): The cost associated with an interruption of electricity supply (i.e., the opportunity cost of electricity).

Wholesale Electricity Market (WEM): Purchase of electricity from generators for the purpose of reselling it to others, who then sell to retail customers.

Zonal pricing: A pricing method in which energy prices vary by zone rather than by node. Zones may be defined by sets of nodes where it is unlikely that the network will experience congestion. Congestion would then be more likely appear at interfaces between zones.

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