

Strengths and Weaknesses of Traditional Arrangements for Electricity Supply

RICHARD SCHMALENSEE



OCTOBER 2019

CEEPR WP 2019-016

Strengths and Weaknesses of Traditional Arrangements for Electricity Supply

Richard Schmalensee¹

Massachusetts Institute of Technology

This essay provides a broad-brush comparison of performance under traditional arrangements for electricity supply with those that emerged after the world-wide wave of restructuring that began in the 1990s. It focuses on the change in reliance on market competition and emphasizes comparisons within the U.S., where traditional and restructured arrangements both exist. It considers both the historical regime, in which essentially all generation capacity is dispatchable, and, more briefly, the emerging regime in which wind and solar generation play important roles. This essay was written to become Chapter 2 in *Handbook on the Economics of Electricity* (J.M. Glachant, P.L. Joskow, and M. Pollitt, eds.) to be published by Edward Elgar.

September 27, 2019

¹ I am indebted to Severin Borenstein, Michael Roberts, and the Handbook editors, especially Paul Joskow, for useful comments.

1. Introduction

Prior to the world-wide wave of restructuring that began in the 1990s,² electricity supply industries (ESIs) differed substantially between nations and even within them. In particular, as Section 2 describes, the extent of ownership by various levels of governments and cooperative institutions varied widely, as did the regulatory regimes faced by investor-owned participants. A common feature of these traditional arrangements, though, was lack of reliance on markets, and a central focus of restructuring was to increase the role of markets and decrease the role of administrative decision-making.

In order to assess strengths and weaknesses of traditional arrangements, a benchmark is required. Section 3 describes a generic post-restructured ESI that will serve here as such a benchmark. The central difference from traditional arrangements is greater reliance on competition in wholesale electricity markets and, less universally, on competition in electricity supply at retail.

Section 3 also introduces the distinction between the *historical* regime, in which, to a first approximation, all generation technologies are dispatchable and government policy is technology-neutral, and the *emerging* regime, in which variable energy resources (VERs), primarily wind and solar generation, and the policies that support them play an increasingly important role.

The historical regime is the focus of Part I of this Handbook. That regime describes the pre-restructuring world everywhere, and it still describes some regions. It is the regime for which restructured institutions were initially designed. Chapter 1 considers optimal pricing and investment in electricity generation in this regime, Chapter 3 describes what is required in practice for post-restructuring wholesale power markets to work well, and Chapters 5-9 provide country studies of restructured ESIs. Chapter 4 examines retail competition in this regime in detail. Section 4, below, provides a broad-brush assessment of the relative strengths and weaknesses of traditional arrangements for electricity supply in the historical regime.

Part II of this Handbook focuses on the emerging regime, in which VERs and the policies that support them have become important enough to have material effects on energy market operations and investment decisions. Chapter 10 describes the new electricity supply technologies involved in that regime, and Chapter 13 examines operational problems posed by high penetration of VER technologies. Chapter 14 considers implications for market design in restructured ESIs. Section 5, below, attempts to

² The law mandating Chile's restructuring was passed in 1986 under Pinochet, while restructuring in England and Wales began in 1989. Though it has received relatively little international attention, Norway's restructuring was both early (1991) and thorough; see IEA (1994, pp. 259-268).

shed some light on the relative strengths and weaknesses of traditional arrangements for electricity supply in the emerging regime.

Because as Section 3 discusses, some areas in the U.S. have been restructured and some have not, and some areas in the country are well-described by the historical regime and others are not, comparisons that hold a range of institutional and economic factors roughly constant are possible. Consequently, I emphasize evidence from the U.S. in both Section 4 and Section 5. Since there is no US experience with systems in which VERs are dominant, however, the discussion in Section 5 is more speculative than that in Section 4. It draws on informal comparisons between two US states in which VERs are already important and there are statutory commitments to carbon-free ESIs by 2045: Hawaii, where traditional arrangements persist, and California, one of the earliest states to restructure.

Section 6 provides a brief summary of the main conclusions and some of their apparent implications.

2. Traditional Arrangements

The first institutions supplying electricity in the late 19th century were generally private, vertically-integrated firms serving a single city or part thereof.³ These enterprises were subject to supervision of various sorts by city governments as a condition for the right to use public rights-of-way for the poles and wires of their distribution systems. After the very early years, enterprises engaged in electricity supply generally became larger and their geographic scope expanded in response to economies of scale in generation, the development of high-voltage transmission, and growth in demand.

By the early 1950s, the basic technology of electricity supply had diffused broadly, but a wide variety of institutional structures had emerged, with mixtures of private ownership and government ownership at national, regional, and local levels. In many countries the institutional structures of ESIs endured until the early 1990s, on the eve of restructuring.⁴ At that time, some countries, including France, Italy, Ireland, and Greece, were served by a single, integrated utility owned by the national government. In England and Wales, generation and transmission were nationalized and integrated, but distribution was in the hands of 12 publicly-owned area electricity boards which were supplied by the national generation and transmission firm. In Germany a small number of integrated regional

³ Before the London Power Company was established in 1925, the city was served by 10 companies that used a variety of voltages and frequencies (https://en.wikipedia.org/wiki/London_Power_Company).

⁴ IEA (1994), on which this paragraph is based, provides a useful overview of the electric power sectors in OECD member nations circa 1992 as well as a good deal of historical information.

generation/transmission companies co-existed with many municipal distributors. The Japanese system was dominated by ten private firms with regional monopolies, while municipalities played a central role in Norway. Vertical integration was the rule rather than the exception, and organized wholesale power markets simply didn't exist.

The electricity supply industry in U.S. in the early 1990s involved a complicated mixture of private ownership and public ownership at various levels of government that had remained fairly stable since the early 1950s.⁵ State regulation of investor-owned utilities spread after 1910 as firms' service areas grew. In the 1920s and 1930s, the issue of public versus private ownership of distribution utilities was put to a vote in many municipalities, but by the 1960s few elections were being held on this issue (Schap 1986). The federal role in regulation and generation expanded substantially in the 1930s, and federal policies were enacted that favored municipal and cooperative utilities.

In the U.S. by 1994, 250 investor-owned utilities, generally vertically integrated into generation, transmission, and distribution, accounted for 76.2% of kilowatt-hour sales to ultimate customers, 2015 utilities owned by federal, state, and local governments accounted for 16.0%, and 939 cooperatives accounted for the remaining 7.8% (US EIA 1995). Only one state (Hawaii) had only investor-owned utilities, and only one state (Nebraska) had no investor-owned utilities. Most publicly-owned enterprises were relatively small distribution-only utilities, but the federally-owned Tennessee Valley Authority (TVA) has long been the largest utility in the nation measured by generation,⁶ and the city-owned Los Angeles Department of Water and Power provided electricity to around 3.5 million people. Thus, even within the U.S. the role of governments in "traditional arrangements" varied considerably from place to place.

Trading electric energy seems to have been more important in the U.S. than in most other countries, probably in part because the number and diversity of industry participants made potential gains from trade unusually important. However, organized wholesale power markets as we know them today did not exist. There was a substantial volume of wholesale transactions, (lightly) regulated at the federal level, of two main sorts. Large utilities entered into requirements contracts that obliged them to meet the demands of publicly-owned (typically municipal) utilities that had little or no generation

⁵ Schmalensee (2016b) discusses the institutional evolution of the US ESI. For a fairly detailed picture of the US ESI and its regulation in 1980, the essential features of which persisted through most of the 1990s, see Joskow and Schmalensee (1983, ch. 2).

⁶ Like the other federal electric utilities, TVA sold (and sells) mainly to other utilities (primarily municipal utilities and cooperatives) rather than to ultimate customers.

capacity. In addition, vertically-integrated firms made so-called coordination sales to each other to reduce costs, in some regions through organized power pools. Some “tight” power pools engaged in central dispatch, running the generating units of all member companies and attempting to minimize total cost. In these cases, cost savings were allocated to pool participants by formula; there were no market prices.

The Public Utilities Regulatory Policy Act (PURPA) of 1978 and the Energy Policy Act of 1992 opened the door to wholesale sales by non-utility generators in the U.S.. But by 1996, when restructuring began, such independent power producers accounted for less than 2% of total net generation (US EIA 2003). Thus, in the U.S., as elsewhere, vertical integration was the rule rather than the exception, and, while there was some inter-utility coordination and the beginnings of wholesale competition, organized wholesale markets did not exist.

3. Restructured Alternatives

The post-1990 restructuring of ESIs around the world had a variety of motivations – including revenue from the sale of government-owned assets – started from a variety of traditional institutional structures, and, as this Handbook indicates, produced a variety of institutional arrangements and market designs.⁷ In the U.S., ESI restructuring followed on the heels of a remarkable period of deregulation and regulatory reform in several important industries.⁸ Globally, ESI restructuring had two main dimensions.

First, in many nations, though not in the U.S., much or all of the generation segment of the industry was privatized. In the U.S., most of the ESI was already investor-owned; interest in privatizing municipal electric utilities had waned; and Republican resistance to privatization of the federal utilities from which their constituents disproportionately benefitted was fierce (Schmalensee 2016). Globally, privatization emerged in the 1990s as a broadly applicable policy tool within and beyond the electric power sector. Privatization has been well-studied, and it has generally been found to improve enterprise efficiency, particularly where a truly hard budget constraint has been imposed by effective competition (Vickers and Yarrow 1988, Megginson and

⁷ On rent-seeking and other motivations for restructuring in the U.S. see Hogan (2002), Borenstein and Bushnell (2015), and the references they cite. On the E.U., see Newbery (2005a) and the references he cites. On the scope of ESI restructuring outside the U.S. and the E.U., see Jamasb et al (2004) and for an illuminating example of restructuring in a developing nation, see Pollitt (2008).

⁸ See MacAvoy and Schmalensee (2014) for an overview of this period of deregulation and set of readings.

Netter 2001). Because privatization has been well-studied and because its effects on ESI structure have varied substantially among nations, I will not consider it further.

Second, the roles of competition and organized markets were greatly enhanced in ESI restructuring. It is generally recognized that transmission is a natural monopoly, so transmission systems must be planned and managed as unitary systems by non-profit entities – ISOs and RTOs in the U.S. and TSOs in the EU – though ownership of transmission assets may be centralized or distributed. This change has created opportunities, relatively recently recognized by the US FERC, for competition of various sorts in transmission investment (Joskow 2019b). Distribution systems are also generally treated as natural monopolies, and the wires and associated equipment are either government-owned or managed by regulated investor-owned utilities. Restructuring has not generally made significant changes in the role of competition in transmission or in the physical delivery of electricity to ultimate customers.

The major change in the role of markets in restructured ESIs has been in generation. All have adopted one form or another of a formal wholesale power market.⁹ Such markets meet about 2/3 of demand in the U.S. and serve all EU Member States and some other nations. In order to ensure that firms that own both generation and transmission assets are not advantaged in competition in bulk power markets, most (and perhaps all) restructured ESIs have imposed some sort of separation between the ownership of generation plants and the operation of transmission facilities. In some cases, divestiture and separate ownership have been required; in others administrative separation with some supervision of behavior has been deemed to be sufficient. Ownership of generating plants was often restructured horizontally as well to reduce concentration in the interest of effective wholesale market competition.

Wholesale markets for electric energy were expected to play a key role, analogous to the role played by central dispatch in tight power pools in the U.S., in ensuring the efficient supply of energy from existing assets. The good news is that competitive markets provide higher-powered incentives for efficiency than either regulation or government ownership. Before restructuring, regulation generally adjusted prices to keep profits within bounds, though often with lags (Joskow 1974), while government enterprises rarely had absolutely hard budget constraints. In both cases, slack in the budget constraint reflected in part the fact that utility managers had better information than those who were charged with supervising them. The bad news is that unregulated or lightly regulated bulk power suppliers may have

⁹ Ahlqvist et al (2018) provide a summary of the main differences between bulk power markets in the U.S. and the E.U.

market power and have every incentive to exercise what power they have (see Chapter 3). Energy markets were also generally expected to play a central role in ensuring efficient investment in generating capacity of various sorts – just as competition in output markets is generally assumed to be sufficient in most other sectors to induce efficient investment.

In distribution, the *delivery* function, the construction and operation of the physical network, is universally performed either by a regulated investor-owned utility or a public enterprise, while the *supply* of electricity has been unbundled from delivery and opened to alternative vendors in some regions with competitive bulk power markets (see Chapter 4 for a full discussion).¹⁰ Such retail choice has been the stated goal in the E.U. since 2003, though the actual extent of competition varies among Member States (Morey and Kirsch 2016). In the U.S., 23 states allowed competition in electricity supply at one time, with strong support from large commercial and industrial customers, but ten states had repealed or suspended these programs by late 2018 (Morey and Kirsch 2016; US EIA 2018).

In economic terms, these structural changes represented shifts in the boundaries between public and investor-owned firms on the one hand and markets on the other, giving different answers to the questions originally posed by Coase (1937). One implicit argument for vertical integration in the traditional arrangements was that investment in and operations of ESIs involved long-lived assets with multiple externalities and were too complex to be managed by spot markets. In addition, particularly in the early days, economies of scale in generation and inelastic demand meant that reliance on markets instead of integration carried a substantial risk of market power.¹¹ The experience of power pools suggested that spot bulk power markets could easily induce efficient supply from existing assets, and the pioneering work of Boiteux (1960, 1964) and Turvey (1968) suggested that competition in bulk power markets could induce the efficient supply of long-lived generation assets.¹² As to the second argument, by the mid-1980s the evidence on scale economies in generation suggested that competitive bulk power markets were possible in at least some regions. Since generation traditionally accounted for 60-65% of total ESI cost, more efficient generation could be expected to have a significant impact on the total cost of electricity and, presumably, on retail rates.

¹⁰ In the U.S., six states that did not have competition at the wholesale level (Arizona, Arkansas, Montana, Nevada, New Mexico, and Oregon), nonetheless allowed retail competition for some customers for some periods.

¹¹ On the argument that complexity and long-lived assets favor vertical integration or complex long-term contracts and a test of that argument, see Joskow (1985), and for a general discussion, see Armstrong and Sappington (2006).

¹² Joskow and Schmalensee (1983) seem easily to have accepted the first of these suggestions but were quite skeptical of the second and argued that getting the right capital stock in place would require a regime built on long-term contracts.

Competition in electricity supply at retail did not seem to involve much complexity, since it essentially involves only a financial relationship between the retail supplier and the customer. There are no changes in physical power flows, and few if any long-lived assets or economies of scale are involved, so the case for continued integration between supply and delivery was even weaker than the case for continued integration of generation and transmission. On the other hand, while distribution traditionally accounted for around 25% of total ESI cost, most of distribution cost was attributable to delivery, not supply, so the scope for reductions in overall system cost seemed to be modest at best. Competition in supply would create opportunities for innovation and differentiation, of course. But competitive suppliers would all buy electricity, a commodity, in the same wholesale market, and most residential meters at the time of restructuring recorded only total monthly consumption. I was among those who felt at that time that the potential for welfare gains from more efficient retail prices was limited, particularly for residential customers. (See Chapter 4 for a rather different view.)

The following two sections compare in broad terms the strengths and weaknesses of traditional vertically integrated utilities with restructured ESIs in which markets, particularly wholesale power markets, play an important role. As noted above, I rely heavily on comparisons in the U.S., where both traditional and restructured arrangements have existed side by side.

Section 4 considers performance in the historical regime, in which VERs are unimportant. This regime existed everywhere before restructuring and still describes ESIs well in some regions in the U.S. and elsewhere. Even though significant federal tax incentives favoring VERs have generally been in effect in the U.S. since the early 1990s (Schmalensee 2010, 2012), as recently as 2014, wind and solar accounted for only 5.1% of net generation in the U.S. as a whole, and only 4.6% if California and Hawaii are excluded (US EIA 2016).¹³ Policies favoring wind and solar generation had little impact on energy markets or generation investment in much of the U.S. until quite recently.

In contrast, under the emerging regime, considered in Section 5 (and in detail in Part II of this Handbook), VERs play a significant and growing role in electricity supply. In Germany, where government support for VERs via feed-in tariffs has been very conspicuous, wind and solar accounted for 28.8% of generation in 2018 (Burger 2019). Some US states have provided strong support for VER generation, mainly through so-called renewable portfolio standards.¹⁴ In California, one of the first US states to

¹³ These statistics include EIA estimates of generation from small-scale solar facilities.

¹⁴ Renewable portfolio standards (RPSs) oblige load-serving entities to obtain specified fractions of the energy they sell via contract from generators in specified locations employing specified technologies; for a discussion, see

restructure, wind and solar accounted for 24.4% of generation in 2018, of which 6.2% was contributed by small-scale solar.¹⁵ Wind and solar accounted for 16.2% of 2018 generation in Hawaii, also a sunny state, of which 9.3% was contributed by small-scale solar. Legislation commits both states to have carbon-free ESIs (by some definition) by 2045.

In these and some other US states, wind and solar now play important roles in generation, and government policies favoring these technologies thus have had important impacts on both energy markets and patterns of generation investment. While the original round of restructuring can be viewed as attempts to improve the performance of well-understood systems, under the emerging regime both traditional and restructured institutions have been tasked with transforming historical-regime ESIs into VER-dominated systems for which there is no operating experience.

4. Comparisons in the Historical Regime¹⁶

At the outset of the restructuring movement, participants seemed to expect that devising workable wholesale markets to guide operations of generation facilities would not be much more complex than simply replacing short-run system marginal cost with a spot market price.¹⁷ After all, there had been many decades of experience building and operating vertically integrated ESIs under the traditional regime, and power engineering had ceased to be an exciting academic field. Restructuring in the traditional regime basically involved attempting to use competition rather than regulation or public ownership to improve performance of well-understood systems.

In the event, restructuring in the historical regime turned out to be much more complex than many expected. Elaborate rules for wholesale energy markets had to be developed over time. Markets had to be created for so-called ancillary services, including frequency regulation and various categories of reserves. In many areas, capacity markets or capacity requirements were added to encourage adequate levels of investment. Market power was a significant concern, particularly early on. The California electricity crisis of 2001-2002 provided a vivid example of the potential costs of a flawed

Schmalensee (2012). It turns out that states that belong to organized bulk power markets are considerably more likely than others to have RPSs.

¹⁵ Except as noted, the statistics in this paragraph are from US EIA (2019). Statistics for small-scale solar are EIA estimates.

¹⁶ Borenstein and Bushnell (2015) provide an overall assessment for the U.S., and Joskow (2008a) provides a more international discussion.

¹⁷ Joskow and Schmalensee (1983) devoted essentially no attention to the design of short-term markets for power. The initial market design in England and Wales used software that had been employed in an earlier power pool and that depended on honest revelation of costs (Newbery 2005b).

market design (Borenstein 2002, Hogan 2002). It also stopped market-oriented ESI reform in the U.S. in its tracks.

In the U.S. and the E.U., wholesale energy markets in ESIs are complex and evolving. For instance, the PJM website contains links to 34 manuals that describe the structure, operations, and processes of its energy market,¹⁸ and the most recent report of its independent market monitor makes 15 recommendations for changes in markets for energy, capacity, and ancillary services (Monitoring Analytics 2019). Ahlqvist et al (2018) and Chapters 5-9 discuss the strengths and weaknesses of a number of complex energy market designs in restructured ESIs. In contrast, retail market regimes in the E.U. and various U.S. states appear relatively simple and do not seem to have changed materially over time – though several US states have simply walked away from retail competition (Morey and Kirsch 2016, US EIA 2018).

The remainder of this section considers evidence, mainly from the U.S., on the impacts of restructuring on (1) the cost and price of supply from existing generating facilities, (2) the level of generation capacity, and (3) the efficiency of prices charged to ultimate customers. Ideally, the wholesale price should equal the minimized marginal cost of generation except during periods of shortage,¹⁹ the stock of generation assets should minimize expected cost and provide an optimal level of reliability, and retail prices at the margin should equal the corresponding wholesale prices adjusted for any marginal transmission and distribution losses.

In principle, an overall assessment of the effects of departures from traditional arrangements should include analyses of effects on power quality (e.g., departures from ideal voltages and frequency), reliability (frequency and duration of outages), and innovation. Data on power quality are not readily available, however. Outages at the bulk power level are too rare in modern systems to permit statistical analysis, and outages at the distribution level are mainly shaped by investment decisions (in particular, tree-trimming and undergrounding of lines) made by entities not generally affected by restructuring. And innovation has mainly been driven by vendors outside ESIs. One would expect replacement of regulation or public ownership of generation with competitive regimes with higher-powered incentives would encourage adoption of innovations generated elsewhere, but data on relative speeds of adoption do not seem to be available. And because there have not been fundamental changes in the incentives facing owners of transmission or distribution facilities, there is no reason to expect a significant

¹⁸ <https://www.pjm.com/library/manuals.aspx>

¹⁹ On the need for price in periods of shortage to exceed the marginal cost of the highest cost generator dispatched in order to provide adequate incentives for generation investment, see Joskow and Tirole (2007) and Joskow (2019a).

restructuring-induced change in the adoption of innovations in transmission or delivery of electricity. Innovation in retailing is discussed below under pricing.

4.1 Generation Operations. In the U.S., direct comparisons of generating plants that were deregulated with those that weren't has provided strong evidence that deregulation plus competition served to reduce generators' operating costs.²⁰ Davis and Wolfram (2012) found greater improvement in the performance of deregulated nuclear generating plants than those that remained subject to conventional rate-of-return regulation. Fabrizio et al (2007) provide similar evidence for a broader set of plants. Cicala (2015) has shown that deregulated coal-fired generators reduced the cost of coal that they burn more than plants that were not deregulated. He does not find the same result for gas-fired plants, which he plausibly attributes to the fact that gas is a homogeneous commodity traded in relatively well-organized markets, making it easier for generators (and regulators) to identify the best price.

In an influential theoretical analysis of rate-of-return regulation, Averch and Johnson (1962) predicted that regulated utilities' costs would be higher than optimal because they had incentives to over-use capital relative to other inputs.²¹ This article has been cited more than 3500 times, but most of the literature it spawned has been theoretical: before the deregulation of some US generating plants, it was hard to perform a clean test of the core Averch-Johnson prediction. Fowlie (2010) and Cicala (2015) were able to perform such tests and to confirm that prediction by showing that deregulated generating plants used less capital-intensive strategies than regulated or publicly-owned plants to comply with environmental regulations that permitted alternative compliance strategies.

While, as noted above, there was trading between firms in the US ESI before restructuring, the development of organized ISO/RTO wholesale power markets seem to have dramatically increased both the volume of and gains from trade. Mansur and White (2012) showed that when a region in the Midwestern U.S. joined the organized PJM market to the east, trade across the boundary that had separated these regions literally tripled overnight, with substantial efficiency gains. Cicala (2019) used the staggered introduction of wholesale markets across the U.S. to identify the impacts of those markets on the allocation of generation among plants and found substantial cost savings at the system level from more efficient use of generation facilities.

²⁰ Newbery (2005b) found more substantial efficiency gains in England and Wales than in Scotland, where competition was less intense.

²¹ They assumed that regulators held the regulated firm's rate of return on assets constant at all times. While this is clearly not descriptive of real US regulation (Joskow 1974), it was certainly plausible that because regulation was concerned with allowing an adequate return on assets, regulated firms would over-use capital relative to other inputs.

All US wholesale markets have moved over time to pricing systems with considerable spatial granularity, following the nodal pricing scheme first proposed by Fred Schweppe and colleagues (1988).²² Wolak (2011) analyzed the transition to nodal pricing in California and found that it yielded considerable benefits.

The evidence in the preceding paragraphs seems to establish that restructuring and the introduction of formal bulk power markets reduced the cost of generating electricity from existing facilities. A concern early on in discussions of restructuring was that with privatization and deregulation, weak competition in bulk power markets might enable generators to capture any efficiency gains – and perhaps more – as monopoly rents (Joskow and Schmalensee 1983, ch. 13).

Because the demand for electricity at the wholesale level is almost perfectly inelastic, when demand is high and available capacity is fully utilized, even relatively small strategic reductions in supply have the potential to produce large increases in price. Such exercises of market power have in fact been significant in some markets at some times, particularly in the early days of restructuring (see Chapter 3). The wholesale power market in England and Wales was initially set up as a duopoly, and market prices were significantly above costs (Wolfram 1999). Structural changes made that market more competitive over time (Newbery 2005b), and market power seems no longer to be a major concern, at least in official circles (Ofgem 2018). Market power was significant in the early days of restructuring (Mansur 2008) in the U.S., particularly in California (Borenstein et al 2002, Joskow and Kahn 2002), and it played a role in the California energy crisis of 2000-2001 (Borenstein 2002, Hogan 2002). Some market power still exists in US bulk power markets in at least some hours: Woerman (2018), for instance, finds that when the ERCOT market is fragmented by transmission congestion, markups over marginal cost rise as predicted by oligopoly theory. All US wholesale power markets are now monitored for significant competitive problems (US FERC 2014, Monitoring Analytics 2019, CA ISO 2019a), and most observers seem satisfied that departures from the competitive ideal are not more dramatic than those in most other real, imperfectly competitive markets.²³

On balance it seems clear that restructuring generally reduced the costs of electricity generation, but it also seems very likely that departures of wholesale electricity prices from costs

²² Hogan (2002) discusses this movement, which was far from smooth. Markets outside the U.S. have been less receptive to nodal pricing; see Ahlqvist et al (2018).

²³ Wolfram (1999) suggested that long-term fixed-price commitments to distribution entities had served to moderate wholesale energy prices in the early days of UK restructuring. Mansur (2007), Bushnell et al (2008), and MacKay and Mercadal (2019) find evidence that vertical commitments had similar effects in US markets in the early years of restructuring.

became larger than under regulation or public ownership, both of which focused more on limiting profits than on controlling costs. Taking into account Oliver Williamson's (1968) rectangles versus triangles argument that antitrust policy should be at least as concerned with cost reductions as with increases in price-cost markups, since cost reductions produce welfare gains that dominate the losses produced by comparable departures of price from cost, and considering the available evidence, it seems at least plausible that restructuring of ESIs has lowered wholesale electricity prices for fixed portfolios of generation assets in the U.S. and the U.K., bringing them closer to minimized marginal cost on average.²⁴

4.2 Generation Capacity. Restructured markets in the U.S. generally had excess generating capacity at the time of restructuring (Borenstein and Bushnell 2015), so the provision of adequate investment incentives was not a major concern. Moreover, the existence of excess capacity seemed to some to confirm either the Averch-Johnson (1962) prediction that regulation would lead to excessive investment or the simpler notion that regulators were not very good at cost control. The designers of early post-restructuring bulk power markets, at least in the U.S. and the U.K., seemed to believe that, as in other industries, profits from selling generators' outputs would provide efficient incentives for the supply of generation capacity.

In order to deal with the problem of market power, all US markets imposed caps on wholesale prices.²⁵ This created another problem, however. Price caps that are below the value of lost load, i.e. what customers would be willing to pay on the margin to avoid having their electricity consumption curtailed, create the so-called "missing money" problem (Joskow 2007). It follows from the classic Boiteux (1960, 1964) - Turvey (1968) models that if price is capped below the value of lost load, competitive energy market revenues cannot provide sufficient revenue to cover the fixed costs of an efficient mix of generating capacities.²⁶ Restructuring thus shifted the capacity risk from over-investment driving up rates to under-investment driving down reliability.

With the exception of Texas,²⁷ US electricity markets established price caps below most estimates of the value of lost load and over time put in place centralized or bilateral markets for capacity

²⁴ This assessment is consistent with Joskow (2007) for the U.S. and the cost-benefit study of Newbery and Pollitt (1997) for England and Wales. Borenstein and Bushnell (2015) provide a less positive assessment of U.S. restructuring.

²⁵ In addition, the US FERC (2016) has imposed caps on bids in wholesale energy markets that mainly focus on recovery of short-run marginal cost.

²⁶ For important generalizations of these classic models, see Joskow and Tirole (2007).

²⁷ The reference here is to the Electric Reliability Council of Texas (ERCOT), the ISO that serves most of the state of Texas. It continues to operate an "energy only" market with no payments for capacity, but since 2014 it has increased

to supplement generators' energy market revenues.²⁸ Additional supplements include out-of-merit-order dispatch for reliability reasons and payments to generating units designated as "reliability must run" to prevent their retirement (see, for instance, CA ISO 2019a, pp. 207-216 and 264-265). These supplements to energy markets have become a very important source of revenue for generators. In the PJM market in 2018, for instance, capacity market revenue would have accounted for 47 percent of total revenues for a new combustion turbine and 36 percent for a new combined cycle unit (Monitoring Analytics 2019, p. 329).

System operators outside the U.S. were slower to add capacity markets or related mechanisms. Despite their prior reluctance, however, after the UK committed in 2013 to adding a capacity market (Grubb and Newbery 2018), other EU member states followed, and by mid-2015, nine member states had capacity mechanisms in place to supplement energy market revenues (European Commission 2016, p. 55).²⁹

Under traditional regulation, utilities' integrated resource plans, which took into account load forecasts, planned retirements, and administratively determined reliability standards, would contain capacity requirements. If the new investments called for by these requirements were approved by regulators, utilities were (in principle, at least) guaranteed to recover the costs involved. Post-restructuring capacity markets rest on similar administrative determinations of capacity requirements. In the U.S., the design of markets to procure the required capacity has not been straightforward, however, and design changes have been common.³⁰ A particularly difficult issue has been determining appropriate penalties for non-availability during shortage conditions. These markets seem generally to have procured adequate capacity, at least in a period of relatively slow load growth, and to have encouraged the development of demand response aggregators, which provide demand reduction services to the wholesale market. Given the continued heavy role of administrative decision-making in this process, however, it is hard to argue that restructuring improved the efficiency of investment in generation capacity substantially or, indeed, at all.

payments for generation above the market-clearing price as its reserve margin shrinks, following a so-called operating reserve demand curve (ERCOT 2014).

²⁸ Since 2004 the California Public Utilities Commission (CPUC) has required all load-serving entities to have contracted for specified levels of capacity, thus establishing a set of bilateral capacity markets (CPUC nd). In the absence of transmission congestion, a single state-wide market would be more efficient (and transparent), but California is a large state, and congestion does occur.

²⁹ The UK capacity market has been suspended since November 2018, when the EU General Court decided that the EU Commission's decision that the market complied with restrictions on state aid had not been properly arrived at.

³⁰ Joskow (2008b) discusses early capacity market designs; Spees et al (2013) provide a more recent assessment.

4.3 Retail Pricing. Wholesale competition makes marginal cost differences over time and space visible at the bulk power level but doesn't directly affect pricing to end-users. Traditionally, regulated and publicly-owned electric utilities charged retail prices that were constant over time and were the same in each utility's service area for customers in each of a few classes. In the U.S., retail tariffs generally involved constant per-kwh prices with only nominal fixed charges. Most customers had no choice of retail supplier, and most had meters that only recorded consumption over fairly long periods – typically a month.

In the wake of restructuring, almost half of US states adopted some form of retail choice, but by the end of 2018 there were active, statewide programs in only 13 states and the District of Columbia (Morey and Kirsch 2016, US EIA 2018). Retail choice has proceeded farther in some other nations, particularly in the E.U. (Morey and Kirsch 2016).

In the U.S., large commercial and industrial consumers pushed hard for retail choice, and it is not surprising that they have generally been enthusiastic participants in active programs (Morey and Kirsch 2016, US EIA 2012). They may be able to obtain lower average prices by dint of monopsony power, which might involve shifting costs to other customers. More importantly, they can afford smart meters and to pay attention to their electricity consumption, and they normally have some ability to shift their demand over time. If they can, in effect, buy at wholesale, they can benefit by shifting load to low-price periods. Larger retailers, for instance, can cool their stores at night when wholesale rates are low, shut off air conditioning when prices rise in the morning, and turn it on again when prices fall.

Even without retail choice, it seems that most commercial and industrial customers in the U.S. have gotten access to time-of-use pricing over time. Wee and Coffman (2018) report that 260 utilities in 47 states offered such pricing in 2016, sometimes on a mandatory basis. Real-time pricing of some sort was offered by 36 utilities in 24 states, typically on an opt-in basis. Whether this pricing appropriately reflects changes in wholesale spot prices is, of course, another question.³¹

Things are different in the household sector. Electricity is a small fraction of most households' spending, and it would not be worth much effort to save a small fraction of that fraction by load shifting.

³¹ For instance, Southern California Edison offers an optional real-time tariff in which energy prices are not directly linked to wholesale spot prices. Rather, this tariff offers time-of-use pricing with six possible prices in each time interval, depending on system conditions. These prices are presumably more predictable than prices under classic real-time pricing, but they are less closely correlated with spot prices.

https://library.sce.com/?10000_group.propertyvalues.property=icr%3Acontent%2Fmetadata%2Fcg%3Atags&10000_group.propertyvalues.operation>equals&10000_group.propertyvalues.0_values=sce-document-library%3Aregulatory%2Fscce-tariff-books%2Felectric%2Fschedules%2Fgeneral-service-%26-industrial-rates

Not surprisingly, there is considerable inertia in retail choice markets in the U.S. and the U.K. (Morey and Kirsch 2016, Ofgem 2018). In some areas, households have the option of paying a premium to buy from suppliers that purchase their power from “green” generators, but these programs have had only limited appeal (Morey and Kirsch 2016, pp. 29-20). Otherwise there seems to have been little in the way of product differentiation.

In most areas with retail choice the incumbent distribution utility offers a default tariff, and consumers are required to take a positive action to switch to another supplier.³² One study found that households in Massachusetts who had switched away from the default supplier were more likely to be low-income than those who had not switched, and the switchers paid higher prices on average (Baldwin 2018). In the U.K. there is considerable inertia in the retail market, and customers who do not switch from the default tariff seem to be the ones who pay the higher prices (Ofgem 2018, ch. 2). In September 2018, the U.K. Parliament put a cap on default tariffs in order to protect inattentive consumers.³³ At least in the U.S. and the U.K., it is hard to argue that retail choice has provided significant net benefits to residential customers.

5. Thoughts on the Emerging Regime for Renewables

In the emerging regime, VERs, particularly wind and solar, account for a large and growing fraction of generation as public policy moves to decarbonize ESIs, and support schemes for these tilt the level playing field that prevailed for the most part in the traditional regime. The maximum output of a wind or solar generator is intermittent – variable and only imperfectly predictable in advance – and actual output can only be dispatched downward from its maximum. This intermittency and the fact that these generators have zero marginal cost means that systems dominated by VERs will necessarily look different from systems in the historical regime (see Chapter 13). ESIs with traditional arrangements will have to solve those technical problems along with their regulators. Restructured ESIs will face another set of problems: how to modify market designs created for the historical regime to induce the adoption of efficient solutions to the new problems of the emerging regime.³⁴ As in the preceding section, I consider in turn (1) generation operations, (2) generation capacity, and (3) pricing at retail.

³² Texas is an exception: all customers served by investor-owned utilities in the ERCOT region are required to make a positive choice of supplier (Morey and Kirsch 2016, p. 4; see also Chapter 4).

³³ <https://www.ofgem.gov.uk/energy-price-caps/about-energy-price-caps>

³⁴ Newbery et al (2018) and Joskow (2019a) address these problems in the context of the E.U. and the U.S., respectively; see also IEA (2016) and Chapters 13 and 14. Pollitt and Anaya (2016) discuss market modifications under way in Germany, the U.K., and New York State.

There is not much experience with the behavior of traditional arrangements in the emerging regime and no formal studies of which I am aware that compare the performance of traditional and restructured ESIs in that regime. In the absence of more comprehensive evidence, I provide anecdotal evidence on similarities and differences between experience under traditional public utility regulation in Hawaii and a restructured system in California.³⁵ As noted above, both states are currently leaders in the U.S. in reliance on wind and solar generation, and both are committed to carbon-free ESIs by 2045.

Both Hawaii and California have better solar resources than most US states, but they are very different from each other on other dimensions. Hawaii has a population of about 1.4 million, living on seven electrically-isolated islands. One island is privately owned; five are served by a single investor-owned, regulated utility, The Hawaiian Electric Company (HECO); and one, with 4.7% of the state's population, is served by a cooperative. Since 2006, new utility-scale generation capacity has been procured under a competitive bidding framework, and a good deal of VER generation is now sold to HECO under power purchase agreements. Hawaii's push toward carbon-free electricity began in 2008, when 90% of the state's electricity was generated with oil (NREL 2008). California's population is much larger, about 39.7 million, and it has substantial transmission linkages to neighboring states. California is mainly served by three investor-owned utilities and one municipal utility, the Los Angeles Department of Light and Power. California's first RPS legislation was passed in 2002, so it began the transformation of its much more complex ESI earlier than Hawaii.

5.1. Generation Operations. A very visible difference between energy markets in the historical and emerging regimes is the occasional appearance of zero and negative prices in the latter.³⁶ These reflect the incentives provided by the most common subsidy schemes and power purchase agreements, which reward VER generation whenever it occurs.³⁷ Under such schemes, renewable generators have a negative private marginal cost and bid accordingly, though their social marginal cost is zero. Baseload generators often operate during negative price periods, choosing to lose money on their production

³⁵ Joskow (2019a) provides a very useful discussion of the California experience.

³⁶ For the Belgian, French and German markets, see De Vos (2016). Schmalensee (2016a) finds negative prices for all the US markets except New England, which barred negative bids during his study period. For more recent experience in New England, see ISO NE (2019, pp. 68-70), and for California see CAISO (2019a, pp. 86-88).

³⁷ Such schemes include feed-in tariffs, production tax credits, and renewable portfolio standards that simply require fixed amounts of generation, with no restrictions on timing. Negative prices also reflect congestion in the transmission system, since at any time there is always some place on earth where incremental electricity would have positive value.

rather than to incur startup and shutdown costs.³⁸ A vertically integrated firm would have the same incentives to run its renewables to receive per-kwh subsidies. And inflexible baseload generators would come under the same economic pressure in either regime because they have essentially no role in VER-dominated power systems.

It is a happy coincidence that as public policies have increased intermittent VER penetration, battery storage that can help manage that intermittency has become cheaper, largely because of scale and learning economies induced by growth of electric vehicles. Storage in ESIs is nothing new, of course: vertically integrated utilities have used pumped hydro storage facilities for decades. But it seems unlikely that pumped hydro capacity can be expanded sufficiently in most regions to cope with the increased supply-side volatility that follows increased VER penetration, and attention now centers on the use of batteries to help dampen price fluctuations.

Legislation passed in 2010 (AB 2514) required large California utilities to procure specified quantities of storage by 2022, and legislation passed in 2016 (AB 2868) required procurement of distributed storage. California utilities have in fact acquired more than the required 1.3GW of storage, but it appears that it has mainly been used in distribution systems and to supply ancillary services, not for intertemporal arbitrage in the wholesale market to manage VER-induced volatility. In February 2018, the US Federal Energy Regulatory Commission (US ERC 2018a) for the first time ordered RTOs and ISOs to adopt “market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets.” As this is written in September 2019, however, the FERC has yet to approve a complete set of such rules.³⁹

In contrast, the Hawaiian utility, HECO, has not been required to acquire battery storage, and its regulator has not had to develop the general rules for its use that would be necessary in a market-based environment. Instead, HECO has been able to gain its regulator’s approval for a number of (relatively) large solar-plus-storage facilities. The developers are selected by competitive bidding, and HECO generally purchases their output under a power purchase agreement (HECO 2019).⁴⁰ It seems to be

³⁸ On the negative impact of subsidized renewables on the economic viability of baseload generators in California, see Bushnell and Novan (2018) and Joskow (2019a)

³⁹ Writing about the E.U., Newbery et al (2018, p. 696) contend that the likely value of battery storage is relatively modest, but they note that “The surrounding incentives and business models that will allow batteries to capture this value still need to be clarified.”

⁴⁰ In contrast to most of the battery storage facilities built in California with three-hour batteries, HECO’s generally include four-hour or five-hour batteries designed to operate during the entire evening peak. Storage that can be charged only by a solar facility, rather than from the grid, is treated as part of the facility and receives a 30% federal

much easier to get relatively novel facilities approved on a case-by-case basis to help satisfy a statutory requirement than to have multi-party agreement on general rules applicable to all such facilities – though this may just reflect the utility’s greater information advantage in unfamiliar situations. Moreover, HECO will almost certainly continue to face lower-powered incentives for efficient use of storage than California market participants.

5.2. Generation Capacity. If most generation is wind or solar, with zero short-run marginal cost, the spot market energy price will often also be zero. Nonetheless, if wholesale prices are capped at the value of lost load, and if demand can respond to price, capacity markets are not necessary to provide incentives for efficient investment. The classic Boiteux (1960, 1964) - Turvey (1968) analysis of the economics of wholesale competition is still valid.⁴¹ The Appendix provides a simple demonstration assuming a smooth demand curve; see Joskow and Tirole (2007) for a more general discussion. With perfectly inelastic supply at every instant, price must be able to vary to equate demand and supply. System operators have been extremely averse to high spot prices in the traditional regime, however, and it is hard to imagine any being willing to live with the more severe high-price periods necessary to provide adequate investment incentives in a market in which the price is often zero.

Thus, it is almost certain that restructured ESIs will continue to rely on capacity mechanisms of one sort or another to supplement generators’ energy market revenues and to drive investment decisions in the emerging regime. Unfortunately, the capacity market designs put in place under the historical regime are not well-suited to meet the challenges of high, subsidized VER penetration, and significant, perhaps fundamental changes will be required.⁴²

When all generators are dispatchable, a market design that rewards promised availability in periods of system stress and imposes a penalty on units that are not available ex post makes perfect sense. Extending that design to intermittent generators is not straightforward, however (see Chapters 13 and 14). It seems reasonable to pay less for one megawatt of solar or wind capacity than for one megawatt of dispatchable capacity, but there is no obviously best way to determine how much less is appropriate in general or for units at specific sites. Any formula can be attacked. Similarly, it seems sensible to penalize an intermittent VER unit less for non-availability than a fossil unit, but it is not clear

tax credit. There is also a technical benefit from combining a battery and a solar generator: they can share a single inverter.

⁴¹ This also seems likely to be true in the presence of competitively-supplied storage: see Schmalensee (2019) for an exploration.

⁴² Bushnell et al (2017) and Joskow (2019a) provide thoughtful discussions.

how to determine how much less is appropriate. Serious penalties for non-availability can cause VER developers to avoid capacity markets entirely and to rely exclusively on power purchase agreements with load-serving entities that have RPS obligations.

US generators, VER or not, that receive state subsidies are naturally advantaged in capacity markets. The FERC (2018b) has ordered ISOs and RTOs with capacity markets to redesign those markets to eliminate subsidy-driven advantages. For markets covering a single state, that should pose no technical challenge, though some have objected that state subsidies may be legitimate attempts to mitigate externalities and FERC's authority to over-rule state policies is not clear. When markets cover multiple states, however, both technical and political complexities mount, and as of September 2019 the required redesigns have not been completed.

Finally, classic capacity markets reward baseload capacity as much as flexible capacity, but under high VER penetration flexible capacity is much more valuable. California has come to recognize this: since at least 2014, the California ISO (CA ISO 2019b) has calculated annual requirements for levels of three types of flexible capacity and passed those requirements on to regulatory authorities, including the Public Utilities Commission. Of course, if gas combustion turbines are the cheapest way to provide such flexibility, this approach is inconsistent with a goal of 100% renewables. Going forward, it may be better to use variants of the technology-neutral "operating reserve demand curve" pioneered in ERCOT (2014), perhaps with a tilt toward renewable generation, or some other innovative mechanism.

Under traditional institutional arrangements, when regulators have approved an investment, that investment normally earns a guaranteed rate of return. There is no need for formal rules distinguishing among different types of generating capacity or other investment; ultimate decisions are project-by-project. Per Averch-Johnson (1962) and the confirming evidence provided by Fowlie (2010) and Cicala (2015), this gives regulated utilities incentives to err in the direction of capital-intensity. In 2016, HECO (2016) filed a 1972-page "Power Improvement Plan", which had been revised at the regulator's request, that presented HECO's plans through 2021 and alternative pathways to become 100% carbon-free by 2045. This long-run system-level planning exercise was clearly informative, and it is hard to believe that it could have been duplicated in a market-driven system. On the other hand, this Plan moves into uncharted territory where the utility's information advantage over the PUC must be substantial. Accordingly, the PUC did not give up its project-by-project approval process. Unlike California, Hawaii has no flexible capacity requirement, but it is worth noting that its newest non-solar plant is designed for flexibility and to run on biodiesel (HECO 2018).

HECO's novel solution of a problem on the island of Molokai (population 7,345) provides an interesting example of the behavior of traditional institutions faced with unfamiliar problems. In 2015 HECO found that if it granted all pending applications for rooftop solar facilities on Molokai, the difference between demand and solar output would occasionally fall below the minimum output level of the diesel generator used to follow load on the island, causing the generator to trip off and the island to black out. The novel solution, approved by the PUC, was to install a "load bank," a dispatchable resistive load that transforms electric power into waste heat (Hawai'i Natural Energy Institute 2019). With the load bank in place, the moratorium on rooftop solar could be lifted. This seems a particularly capital-intensive solution, and competition might have produced a lower-cost alternative. But setting the rules of the competition for solving such a novel problem might have delayed the outcome for several years.

5.3. Retail Pricing. Imelda et al (2018) argue that real-time pricing would not add much social value to Hawaii's current ESI but that it could substantially reduce the cost of moving to 100% renewables by inducing load-shifting. The clearest example of what is possible there with existing technology for commercial and industrial customers is making ice when power is cheap on the margin and using that ice for cooling when power is expensive. While the quantitative results in this study are clearly specific to Hawaii, it seems clear that regions in the emerging regime, including both California and Hawaii, would benefit substantially by transitioning away from flat per-kwh rates.

I have argued that retail choice could help advance such a transition, but neither California nor Hawaii have retail choice at the individual customer level.⁴³ HECO and the three main investor-owned utilities in California all offer time-of-use rates to commercial and industrial customers, but only Southern California Edison (SCE) offers a form of optional real-time pricing.⁴⁴ All also offer residential time-of-use pricing, but it is the default in California and an option in Hawaii. In both cases it seems that concerns that customers might opt for flat rates led to suppression of within-day rate differences, so it likely that less load shifting will be induced than would be optimal.

Neither Hawaii nor California have moved as aggressively to real-time pricing as economists would prescribe, and the differences between them seem minor. Regulators in both states seem similarly reluctant to impose change on consumers. It will be interesting to see whether this general

⁴³ In California and six other states, Community Choice Aggregation (CCA) can provide a form of competition (U.S. EPA n.d.) Under CCA municipalities may seek competitive bids from retail suppliers to serve *all* of the eligible customers in the municipality (subject to a customer opt-out option) at a price determined through a competitive bidding process.

⁴⁴ See Note 31, above

resistance persists as system marginal costs and wholesale prices become more volatile in coming decades.

6. Some Tentative Conclusions

The evidence suggests that restructuring generally produced positive – but not dramatic – net benefits in the historical regime, at least after the surprisingly difficult process of market design was largely worked through. Generation costs have been reduced by stronger incentives and reduced transactions costs, and it seems unlikely that those gains have been erased by greater exercise of market power. Administrative supervision plays a significant role in the provision of generation capacity, as in the traditional structure. While capacity risks seem to have shifted from excessive capacity under regulation to insufficient investment with reliance on markets, capacity markets and related devices seem to have reduced those risks to tolerable levels, at least during a period of low load growth. Efficient pricing at the wholesale level has not led to more efficient retail pricing for most residential customers, though large commercial and industrial customers seem to have had increasing access to tariffs that reflect system conditions.

Today's restructured and traditional systems were both designed for the historical regime and are facing new challenges in the emerging regime in which VERs and the policies that support them are of substantial and growing importance. It seems clear that market designs in restructured systems will need fundamental change. A comparison of California and Hawaii suggests that traditional systems have more agility to meet the new challenges of the emerging regime in a timely fashion, since utilities and their regulators can engage in classic integrated resource planning and project-by-project decision-making without needing to devise and adopt complex new market designs. On the other hand, in the new terrain of the emerging regime, the information advantage of utilities over regulators is likely to be substantial, and the flip side of greater agility may be higher costs and rates than could be attained under competition.

References

- Ahlqvist, Victor, Pär Holmberg, and Thomas Tangerås (2018), 'Central- versus Self-Dispatch in Electricity Markets', Cambridge, UK: Cambridge Working Papers in Economics 1902, accessed 29 July 2019 at <http://www.econ.cam.ac.uk/research-files/repec/cam/pdf/cwpe1902.pdf>
- Armstrong, Mark, and David E.M. Sappington (2006), 'Regulation, Competition, and Liberalization', *Journal of Economic Literature*, 44(2): 325-366.
- Averch, Harvey and Leland L. Johnson (1962), 'Behavior of the Firm Under Regulatory Constraint', *American Economic Review*, 52 (5): 1052–1069.
- Baldwin, Susan M. (2018), 'Are Consumers Benefiting from Competition?' Commonwealth of Massachusetts, Attorney General's Office, March, accessed 29 July 2019 at <https://www.mass.gov/files/documents/2018/03/29/Comp%20Supply%20Report%20Final%20032918.pdf>.
- Boiteux, Marcel (1960). "Peak Load Pricing," *Journal of Business*, 33(2): 157-179.
- _____ (1964). "The Choice of Plant and Equipment for the Production of Electric Energy." In J. Nelson (Ed.), *Marginal Cost Pricing in Practice*. Englewood Cliffs, N.J.: Prentice-Hall.
- Borenstein, Severin (2002), 'The Trouble with Electricity Markets', *Journal of Economic Perspectives*, 16(1): 191-211.
- _____ and James Bushnell (2015), 'The U.S. Electricity Industry after 20 Years of Restructuring', *Annual Review of Economics*, 7: 437-463.
- _____, _____, and Frank A. Wolak (2002), 'Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market', *American Economic Review*, 92(5): 1376-1405.
- Burger, Bruno (2019), *Net Public Electricity Generation in Germany in 2018*, Fraunhofer Institute for Solar Energy Systems ISE Report, 5 January, accessed 29 July 2019 at https://www.ise.fraunhofer.de/content/dam/ise/en/documents/News/Stromerzeugung_2018_2_en.pdf.
- Bushnell, James, Erin Mansur, and Celeste Saravia (2008), 'Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets', *American Economic Review*, 98(1): 237-266.
- _____, Michaela Flagg, and Erin Mansur (2017), 'Electricity Capacity Markets at a Crossroads', University of California, Berkeley, Energy Institute @ Haas WP-279, April, accessed 29 July 2019 at <https://ei.haas.berkeley.edu/research/papers/WP278Updated.pdf>
- _____ and Kevin Novan (2018), 'Setting With The Sun: The Impacts of Renewable Energy on Wholesale Power Markets', University of California, Berkeley, Energy Institute @ Haas WP-292, August, accessed 27 July 2019 at <https://ei.haas.berkeley.edu/research/papers/WP292.pdf>.
- California Independent System Operator (CA ISO) (2019a), *2018 Annual Report on Market Issues and Performance, Department of Market Monitoring*, May, accessed 29 July 2019 at <http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf#search=annual%20report%20on%20market%20issues%20and%20performance>
- _____ (2019b), *Flexible Capacity Needs Assessment for 2020*, May, accessed 28 July 2019 at <http://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf>

California Public Utilities Commission (CPUC) (nd), *Resource Adequacy*, website, accessed 29 July 2019 at <https://www.cpuc.ca.gov/ra/>

Cicala, Steve (2015), 'When Does Regulation Distort Costs? Lessons from Fuel Procurement in US Electricity Generation', *American Economic Review*, 105(1): 411-444.

_____ (2019), 'Imperfect Markets versus Imperfect Regulation in U.S. Electricity Generation', University of Chicago, Working Paper, May, accessed 29 July 2019 at http://home.uchicago.edu/~scicala/papers/elec_gov_v_mkt/elec_gov_v_mkt_draft_2.pdf

Coase, Ronald (1937), 'The Nature of the Firm', *Economica*, ns. 4 (16), 386-405.

Davis, Lucas W., and Catherine Wolfram (2012), 'Deregulation, Consolidation, and Efficiency: Evidence from US Nuclear Power', *American Economic Journal: Applied Economics*, 4(4): 194-225.

De Vos, Krisof (2015), 'Negative Wholesale Electricity Prices in the German, French, and Belgian Day-Ahead, Intra-Day and Real-Time Markets', *The Electricity Journal*, 28(4): 36-50.

Electric Reliability Council of Texas (ERCOT) (2014), *About the Operating Reserve Demand Curve and Wholesale Prices*, Technical Report, accessed 29 July 2019 at http://www.ercot.com/content/news/presentations/2014/ORDCUpdate_FINAL1.pdf

European Commission (2016), *Final Report of the Sector Inquiry on Capacity Mechanisms: Commission Staff Working Document*, Brussels, 30 November, SWD(2016) 385 final, accessed 29 July 2019 at http://ec.europa.eu/competition/sectors/energy/capacity_mechanism_swd_en.pdf

Fabrizio, Kira R., Nancy L. Rose, and Catherine D. Wolfram (2007), 'Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency', *American Economic Review*, 97(4): 1250-1277

Fowlie, Meredith (2010), 'Emissions Trading, Electricity Restructuring, and Investment in Pollution Abatement', *American Economic Review*, 100(3): 837-869.

Grubb, Michael, and David Newbery (2018), 'UK Electricity Market Reform and the Energy Transition: Emerging Lessons', *Energy Journal*, 39(6): 1-15.

Hawaiian Electric Company (HECO) (2016), *Power Supply Improvement Plan*, accessed 28 July 2019 at <https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/power-supply-improvement-plan>

_____ (2018), *Hawaiian Electric, U.S. Army Announce Completion of Schofield Generating Station*, Press Release, 31 May, accessed 28 July 2019 at https://www.hawaiianelectric.com/documents/about_us/news/2018/20180531_schofield_generating_station.pdf

_____ (2019), *New Solar-Plus-Storage Projects Set Low-Price Benchmark for Renewable Energy in Hawai'i*, Honolulu, Press Release, 3 January, accessed 29 July 2019 at https://www.hawaiianelectric.com/documents/about_us/news/2019/20190103_hawaiian_electrics_new_solar_plus_storage_projects_set_low_price_benchmark.pdf

Hawai'i Natural Energy Institute (2019), *Dynamic Load Bank: A Practical Solution to Enable Very High Penetration Rooftop PV*, Press Release, University of Hawai'i, 12 July, accessed 29 July 2019 at <https://www.hnei.hawaii.edu/sites/www.hnei.hawaii.edu/files/Molokai%20Dynamic%20Load%20Bank.pdf>

Hogan, William W. (2002), 'Electricity Market Restructuring: Reforms of Reforms', *Journal of Regulatory Economics*, 21(1): 103-132.

Imelda, Fripp, M., and Roberts, M. J. (2018), 'Variable Pricing and the Cost of Renewable Energy', NBER Working Paper 24712, June.

International Energy Agency (IEA) (1994), *Electricity Supply Industry: Structure, Ownership and Regulation in OECD Countries*. Paris: OECD.

_____ (2016), *Repowering Markets: Market Design and Regulation During the Transition to Low-Carbon Power Systems*, Paris: OECD, accessed 29 July 2019 at <https://webstore.iea.org/re-powering-markets>.

ISO New England (ISO NE)(2019), *Annual Markets Report, Internal Market Monitor*, 23 May, accessed 29 July 2019 at <https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf>.

Jamasb, Tooraj, Raffaella Mota, David Newbury, and Michael Pollitt (2004), 'Electricity Reform in Developing Countries: A Survey of Empirical Evidence on Determinants and Performance', Cambridge Working Papers in Economics CWPE 0439, accessed 29 July 2019 at <https://www.repository.cam.ac.uk/bitstream/handle/1810/456/ep47.pdf?sequence=1>

Joskow, Paul L. (1974), 'Inflation and Environmental Concern: Structural Change in the Process of Public Utility Rate Regulation', *Journal of Law and Economics*, 17(2): 291-327.

_____ (1985), 'Vertical Integration and Long-term Contracts: The Case of Coal-Burning Electric Generating Plants', *Journal of Law, Economics, and Organization*, 1(1): 33-80.

_____ (2007), 'Markets for Power in the United States: An Interim Assessment', *Energy Journal*, 27(1): 1-36.

_____ (2008a), 'Lessons Learned from Electricity Market Liberalization', *Energy Journal*, 34 (Special Issue): 9-42.

_____ (2008b), 'Capacity Payments in Imperfect Electricity Markets: Need and Design', *Utilities Policy*, 16(3): 159-170.

_____ (2019a), 'Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The US Experience', *Oxford Review of Economic Policy*, 35 (2): 291-331.

_____ (2019b), 'Competition for Electric Transmission Projects in the U.S.: FERC Order 1000', MIT Center for Energy and Environmental Policy Research, Working Paper 2019-004, March.

_____ and Richard Schmalensee (1983), *Markets for Power: An Analysis of Electrical Utility Deregulation*, Cambridge: MIT Press.

_____ and Edward Kahn (2002), 'A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000', *Energy Journal*, 23(4): 1-35.

_____ and Jean Tirole (2007), 'Reliability in Competitive Electricity Markets', *Rand Journal of Economics*, 38(1): 60-84.

MacAvoy, Paul W., and Richard Schmalensee, eds. (2014) *The Causes and Effects of Deregulation*. (2 Vols.), Cheltenham, UK: Edward Elgar.

MacKay, Alexander, and Ignacia Mercadal (2019), 'Shades of Integration: The Restructuring of U.S. Electricity Markets', Harvard Business School, Working Paper, 18 September.

Mansur, Erin T. (2007), 'Upstream Competition and Vertical Integration in Electricity Markets', *Journal of Law and Economics*, 50(1): 125-156.

_____ (2008), 'Measuring Welfare in Restructured Electricity Markets', *Review of Economics and Statistics*, 90(2): 369-386.

_____ and Matthew W. White (2012), 'Market Organization and Efficiency in Electricity Markets', Working Paper, Dartmouth College, accessed 29 July 2019 at http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.htm

Meggison, William L., and Jeffrey M. Netter (2001), 'From State to Market: A Survey of Empirical Studies on Privatization', *Journal of Economic Literature*, 39(2): 321-389.

Monitoring Analytics, LLC (2019), *State of the Market Report for PJM, Volumes 1 and 2*, PJM Interconnection, LLC, 14 March, accessed 29 July 2019 at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml

Morey, Mathew J., and Laurence D. Kirsch (2016), *Retail Choice in Electricity: What Have We Learned in 20 Years?* Madison, WI, Christensen Associates Energy Consulting, LLC, February 16, accessed 29 July 2019 at https://hepg.hks.harvard.edu/files/hepg/files/retail_choice_in_electricity_for_emrf_final.pdf

National Renewable Energy Laboratory (NREL) (2018), *Hawaii Clean Energy Initiative: 2008-2018*, DOE/GO-102018-5063, January, accessed 29 July 2019 at <https://www.nrel.gov/docs/fy18osti/70709.pdf>

Newbery, David (2005a), 'Introduction', *Energy Journal*, 26 (Special Issue):1-10

_____ (2005b), 'Electricity Liberalization in Britain: The Quest for a Satisfactory Wholesale Market Design', *Energy Journal*, 26 (Special Issue): 43-70.

_____, and Michael G. Pollitt (1997), 'The Restructuring and Privatization of the CEBG: Was it Worth It?' *Journal of Industrial Economics*, 45(3): 269-303.

_____, _____, Robert A. Ritz, and Wadim Strielkowski (2018), 'Market Design for a High-renewables European Electricity System', *Renewable and Sustainable Energy Reviews*, 91: 695-707.

Ofgem (2018), *State of the Energy Market 2018*, London, 11 October, accessed 29 July 2019 at https://www.ofgem.gov.uk/system/files/docs/2018/10/state_of_the_energy_market_report_2018.pdf

Pollitt, Michael (2008), 'Electricity Reform in Argentina: Lessons for Developing Countries', *Energy Economics*, 30(4): 1436-1567.

_____ and Karim L. Anaya (2016), 'Can Current Electricity Markets Cope with High Shares of Renewables? A Comparison of Approaches in Germany, the UK, and the State of New York', *Energy Journal*, 37(S12); 69-88.

Schap, David (1986), *Municipal Ownership in the Electric Utility Industry*, New York: Praeger.

Schmalensee, Richard (2010), "Renewable Electricity Generation in the United States." In *Harnessing Renewable Energy in Electric Power Systems* (B. Moselle, J. Padilla, and R. Schmalensee, eds.), Washington/London: RFF Press, pp. 209-232.

_____ (2012), 'Evaluating Policies to Increase the Generation of Electricity from Renewable Energy,' *Review of Environmental Economics and Policy*, 6(Winter): 45-64.

_____ (2016a), 'The Performance of U.S. Wind and Solar Generating Units', *Energy Journal*, 37(1): 123-151.

_____ (2016b), 'Socialism for Red States in the Electric Utility Industry', *Journal of Competition Law and Economics*, 12(3): 477-494.

_____ (2019), 'On the Efficiency of Competitive Energy Storage', MIT Center for Energy and Environmental Policy Research, Working Paper WP-2019-009, accessed 27 July 2019 at <http://ceep.mit.edu/publications/working-papers>.

Schweppe, Fred, Michael Caramanis, Richard Tabors, and Roger Bohn (1988), *Spot Pricing of Electricity*, Norwell, MA: Kluwer Academic Press, 1988.

Spees, Kathleen, Samuel A. Newell, and Johannes P. Pfeifenberger (2013), 'Capacity Markets – Lessons Learned from the First Decade', *Economics of Energy & Environmental Policy*, 2(2): 1-26.

Turvey, Ralph (1968). *Optimal Pricing and Investment in Electricity Supply: An Essay in Applied Welfare Economics*. Cambridge, MA: MIT Press.

U.S. Energy Information Agency (US EIA) (1995), *Electric Sales and Revenue: 1994*, Washington: U.S. EIA, November, DOE/EIA-0540(94), accessed 28 July 2019 at https://www.eia.gov/electricity/sales_revenue_price/archive/054094.pdf

_____ (2003), *Electric Power Annual 2001*, Washington: U.S. EIA, March, DOE/EIA-0348(2001), accessed 29 July 2019 at <https://www.eia.gov/electricity/annual/archive/03482001.pdf>

_____ (2012), 'State Electric Retail Choice Programs Are Popular with Commercial and Industrial Customers', *Today in Energy*, 14 May, accessed 29 July 2019 at <https://www.eia.gov/todayinenergy/detail.php?id=6250>.

_____ (2016), *Electric Power Annual 2015*, Washington: US EIA, November, accessed 12 September 2019 at <https://www.eia.gov/electricity/annual/archive/03482015.pdf>

_____ (2018), 'Electricity Residential Retail Choice Participation has Declined since 2014 Peak', *Today in Energy*, 8 November, accessed 29 July 2019 at <https://www.eia.gov/todayinenergy/detail.php?id=37452>

_____ (2019), *Electric Power Monthly, February 2019*, accessed 29 July 2019 at <https://www.eia.gov/electricity/monthly/archive/february2019.pdf>

U.S. Environmental Protection Agency (US EPA)(n.d.), 'Community Choice Aggregation', accessed 9 September 2019 at <https://www.epa.gov/greenpower/community-choice-aggregation>

U.S. Federal Energy Regulatory Commission (US FERC) (2014), *Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets*, Washington: U.S. FERC, Docket No. AD14-14-000, October, accessed 29 July 2019 at <https://ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf>

_____ (2016), *Order No. 831: Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Washington: U.S. FERC Docket No. RM16-5-000, November, accessed 9 September 2019 at <https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf>

_____ (2018a), *Order No. 841: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Washington, 15 February, accessed 29 July 2019 at <https://ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf>

_____ (2018b), *Order Rejecting Proposed Tariff Revisions Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, Washington, 29 June, accessed 27 July 2019 at <https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf>.

Vickers, John, and George Yarrow (1988). *Privatization: An Economic Analysis*. Cambridge, MA: MIT Press.

Wee, Sherilyn, and Makena Coffman (2018), 'Integrating Renewable Energy: A Commercial Sector Perspective on Price-Responsive Load Shifting', University of Hawai'i, UNHERO Report, 23 July, accessed 27 July 2019 at https://uhero.hawaii.edu/assets/IntegratingRenewableEnergy_PriceResponsiveLoadShifting.pdf

Williamson, Oliver E. (1968), 'Economics as an Antitrust Defense: The Welfare Tradeoffs', *American Economic Review*, 58(1): 18-36.

Woerman, Matt (2018), 'Market Size and Market Power: Evidence from the Texas Electricity Market', University of California, Berkeley, EI@Haas Working Paper WP-298, 3 December, accessed 29 July 2019 at https://ei.haas.berkeley.edu/research/abstracts/abstract_wp298.html

Wolak, Frank A. (2011), 'Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets', *American Economic Review: Papers & Proceedings*, 101(3): 247-252.

Wolfram, Catherine D. (1999), 'Measuring Duopoly Power in the British Electricity Spot Market', *American Economic Review*, 89(4):805-826.

Appendix

Consider a simple power market with 100% renewables and price-responsive demand. Renewable capacity is R , and the maximum renewable generation in short periods (hours, days) is αR , where α is a random variable on $[0,1]$ with distribution function F and density f . Assume for notational simplicity that the smooth market inverse demand function is non-stochastic, $P = d(Q)$, with $0 = d(M)$. (If the market demand curve were stochastic, the first two terms in equation (1) would be replaced by the expectation over M of those terms.) I assume that if $\alpha > M/R$, so that maximum renewable generation exceeds maximum consumption, the excess generation can be costlessly curtailed, and the market price of energy is zero. Let the unit per-period cost of renewable capacity be γ .

A social planner wants to maximize expected consumer surplus minus capital cost:

$$(1) \quad E(U) = [1 - F(M/R)] \int_0^M d(t) dt + \int_0^{M/R} \left[\int_0^{\alpha R} d(t) dt \right] f(\alpha) d\alpha - \gamma R.$$

The first term reflects the assumption that when $\alpha > M/R$ and there is surplus generation, $Q = M$ and consumer surplus is the integral under the inverse demand curve from zero to M . The second term is the probability-weighted sum of surpluses for values of α less than M/R .

Differentiation yields the first-order condition for a social optimum:

$$(2) \quad dE(U)/dR = \int_0^{M/R} [\alpha d(\alpha R)] f(\alpha) d\alpha - \gamma = 0.$$

For any value of α less than M/R , the market price of energy is $d(\alpha R)$, and the output from a unit of renewable capacity is just α . Condition (2) is thus a break-even condition for competitive equilibrium: it equates the expected revenue per unit of renewable capacity to the corresponding marginal cost, γ . It is easy to show that the second-order condition for a maximum of $E(U)$ is satisfied as long as demand is downward-sloping.

Thus, with no caps on energy prices and price-responsive demand, the classic Boiteux-Turvey result holds in this pure-VER case: competitive equilibrium in the energy market corresponds to the socially optimal level of capacity.



MIT Center for Energy and Environmental Policy Research

Since 1977, the Center for Energy and Environmental Policy Research (CEEPR) has been a focal point for research on energy and environmental policy at MIT. CEEPR promotes rigorous, objective research for improved decision making in government and the private sector, and secures the relevance of its work through close cooperation with industry partners from around the globe. Drawing on the unparalleled resources available at MIT, affiliated faculty and research staff as well as international research associates contribute to the empirical study of a wide range of policy issues related to energy supply, energy demand, and the environment.

An important dissemination channel for these research efforts is the MIT CEEPR Working Paper series. CEEPR releases Working Papers written by researchers from MIT and other academic institutions in order to enable timely consideration and reaction to energy and environmental policy research, but does not conduct a selection process or peer review prior to posting. CEEPR's posting of a Working Paper, therefore, does not constitute an endorsement of the accuracy or merit of the Working Paper. If you have questions about a particular Working Paper, please contact the authors or their home institutions.

**MIT Center for Energy and
Environmental Policy Research**
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139
USA

Website: ceepr.mit.edu

MIT CEEPR Working Paper Series is published by
the MIT Center for Energy and Environmental
Policy Research from submissions by affiliated
researchers.

Copyright © 2019
Massachusetts Institute of Technology

For inquiries and/or for permission to reproduce
material in this working paper, please contact:

Email ceepr@mit.edu
Phone (617) 253-3551
Fax (617) 253-9845