In the 1990s, the Federal Energy Regulatory Commission (FERC) stopped treating power generation as a regulated monopoly and supported the development of competitive electricity markets. Competition has encouraged innovation and reduced costs, but the payment system FERC and grid operators developed has struggled to provide low-cost electricity without leaving itself vulnerable to market power abuses. In a payment system based on marginal costs, generators necessary for grid reliability cannot recover their fixed costs unless they charge high prices when supply is scarce. However, because these generators have market power, permitting them to recover their fixed costs leaves energy markets vulnerable to market manipulation. To mitigate market power abuses, every grid operator in the United States has introduced offer caps that limit revenues available in energy markets. Offer caps can prevent some generators from recovering their fixed costs, leading to a “missing money” problem as critical suppliers are forced out of business and potential new entrants cannot cover their start-up costs. Today, growing penetration of renewables is exacerbating the missing money problem. Regulators and grid operators are responding by administratively pricing certain resources and supporting specific units deemed too important to retire. These interventions lead to excess capacity and undermine competitive markets. As a result, current regulatory responses to the missing money problem recreate the inefficiencies that competitive markets were designed to solve, and they do so under questionable legal authority and at the expense of a clean energy grid.

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Rather than quietly revive cost-of-service rate regulation, this Article argues that FERC should simplify reserve requirements, stop counteracting state clean energy programs, and support the development of competitive markets for services that support grid reliability. Specifically, FERC and grid operators need not administratively reprice resources or force load-serving entities (LSEs), which distribute electricity to consumers, to transact with specific generators. Instead, the Commission should support long-term resource procurement markets that would be built on top of today’s short-term energy markets. Wholesale markets would consist primarily of short-term energy dispatch and balancing markets. They would not be relied on to ensure that revenues are sufficient to maintain resource adequacy. If LSEs were permitted to determine for themselves how to comply with resource procurement requirements, they could balance renewable policies, flexibility needs, and reserve mandates. This approach would maintain reliability while respecting FERC’s jurisdictional limits. Most importantly, it would prevent the Commission from quietly revising cost-of-service regulation in regions that ostensibly abandoned that market structure decades ago.

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INTRODUCTION

The Federal Energy Regulatory Commission (FERC) is so worried about cheap renewable energy sources that in December 2019, it ordered PJM, a regional transmission organization (RTO) that oversees electricity sales to sixty-five million Americans,1 to prohibit renewables from submitting low bids in capacity markets.2 One expert projected that this intervention, along

2 See Calpine Corp., 163 FERC ¶ 61,236, slip op. at 6 (June 29, 2018). Capacity markets refer to markets that compensate generators for being available to provide energy—not for actually
with a similar intervention in New England, could cost between $9.1 billion and $24.6 billion annually.\(^3\) FERC explained that this handout was necessary to ensure that energy markets remain “grounded in fundamental principles of supply and demand.”\(^4\) This is a curious justification. Basic economic theory teaches that markets are working when competition drives prices down.\(^5\) FERC’s order turned this principle on its head.

Similar concerns prompted FERC to bail out a large natural gas power plant in Massachusetts by allowing the company to recover over $400 million from ratepayers.\(^6\) ISO-NE, the grid operator that oversees electricity sales in New England, determined that its “reliability-centered framework [was] unable to ensure adequate fuel security.”\(^7\) This market failure, according to ISO-NE and a majority of FERC Commissioners, “demand[ed] near-term, out-of-market support until any long-term, market-based solutions that are identified as necessary can be implemented.”\(^8\)

FERC is not the only regulator concerned that renewables pose a threat to the power grid. In 2018, Energy Secretary Rick Perry said that renewable subsidies “threaten to undercut the performance of the grid well into the future.”\(^9\) On this basis, Perry’s Department of Energy (DOE) proposed a national system of subsidies for coal and nuclear power plants.\(^10\) The federal

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\(^3\) Protest of Clean Energy Advocates at 7, PJM Interconnection, L.L.C., 163 FERC ¶ 61,236 (2018) (No. ER08-1314). Commissioner Glick calculated that the Order will increase capacity markets costs by at least $2.4 billion per year. Calpine Corp., 169 FERC ¶ 61,239 (Dec. 19, 2019) (Glick, Comm’r, dissenting), slip op. at 23.

\(^4\) Calpine Corp., 163 FERC ¶ 61,236, slip op. at 3.

\(^5\) See ADAM SMITH, AN INQUIRY INTO THE NATURE AND CAUSES OF THE WEALTH OF NATIONS 77 (R.H. Campbell et al. eds., Liberty Fund 1981) (1776) (“A dyer who has found the means of producing a particular colour with materials which cost only half the price of those commonly made use of, may, with good management, enjoy the advantage of his discovery as long as he lives. . . .”).

\(^6\) ISO New England Inc., 165 FERC ¶ 61,202, slip op. at 1 (Dec. 3, 2018); see also id. at 22 (reporting one commenter’s estimate of the proposal’s $400 million cost).

\(^7\) ISO New England Inc., 164 FERC ¶ 61,003 (July 2, 2018) (Chatterjee, Comm’r, concurring), slip op. at 1-2.

\(^8\) Id.


intervention would have cost billions.\textsuperscript{11} DOE was concerned that “price suppression is occurring in [electricity] markets. . . . [I]n some regions, these low prices have put pressure on baseload units, particularly zero-carbon emissions nuclear generation.”\textsuperscript{12} Again, regulators worried that renewables and other low-cost resources were threatening to drive crucial generators out of business.

While some of these regulatory interventions seem pretextual, they are also symptomatic of a long-term trend that will inevitably transform American electricity markets. For most of the twentieth century, regulators treated electricity as a natural monopoly.\textsuperscript{13} To ensure that suppliers satisfied consumer demand, regulators protected utilities from competition and permitted them to charge rates sufficient to cover their costs. In exchange, generators agreed to provide nondiscriminatory access to electricity and cap prices.\textsuperscript{14} While this system provided reliable electricity,\textsuperscript{15} critics complained that it limited consumer choice, failed to promote innovation, rewarded utilities for overinvesting in supply, and reduced incentives to retire uneconomic generators.\textsuperscript{16}


\textsuperscript{13} See, e.g., 66 PA. CONS. STAT. § 1501 (2019) (prescribing that “[t]he commission shall have sole and exclusive jurisdiction to promulgate rules and regulations for the allocation of natural or artificial gas supply by a public utility”). Under the natural monopoly approach, utility commissions charged rates according to the following equation: $R = Br + O$, where \( R \) represents the utility’s total revenue requirements, \( B \) represents the rate base, \( r \) represents the permissible rate of return on investment, and \( O \) represents permissible operating expenses. See SIDNEY A. SHAPIRO & JOSEPH P. TOMAIN, REGULATORY LAW AND POLICY: CASES AND MATERIALS 109 (3d ed. 2002).

\textsuperscript{14} See, e.g., 66 PA. CONS. STAT. § 1501 (“[E]very public utility may have reasonable rules and regulations governing the conditions under which it shall be required to render service.”); Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (Starr, J., concurring) (“The utility business represents a compact of sorts; a monopoly on service in a particular geographical area . . . is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market.”). See generally Mark A. Jamison, Regulation: Price Cap and Revenue Cap, in 3 ENCYCLOPEDIA OF ENERGY ENGINEERING AND TECHNOLOGY 1245 (Barney L. Capehart ed., 2007) (describing the operation of “price caps”).


\textsuperscript{16} See 1 ALFRED KAHN, THE ECONOMICS OF REGULATION 25-32, 53-54 (1970) (arguing that this regulatory approach inadequately incentivizes innovation and cost control).
In the 1990s, FERC began to encourage a “market-based” approach to promote competition and control costs. Under this “restructured” model, an independent grid operator determines demand for electricity, solicits bids from generators, and clears enough bids to meet demand. The grid operator clears bids starting with the lowest bid but ultimately pays every generator the price bid by the highest clearing bidder to clear. Generators bid at their marginal cost of generation. If a generator bids below its marginal costs, it risks having to provide electricity even when it would lose money in doing so. An above-marginal-cost bid risks failing to clear when it would be profitable for the generator to operate.

This system promotes competition and keeps short-run costs low, but it has struggled to maintain sufficient reserves to satisfy demand for electricity. Generators that are dispatched infrequently or that operate on the margin cannot make a profit or recover their costs. These plants are known as “peaking plants” and generally operate when demand is high (generally on hot days in the summer or cold days in the winter). Without them, grid operators would not be able to meet peak demand. When regulators limit energy market clearing prices, which every grid operator in the United States does, they prevent these resources from fully recovering their costs, which

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17 See infra Section I.B; Section II.B.
19 See PJM Interconnection, L.L.C., 115 FERC ¶ 61,079, slip op. at 2 (Apr. 20, 2006) (“[T]he Commission finds that as a result of a combination of factors, PJM’s existing capacity construct is unjust and unreasonable as a long-term capacity solution, because it fails to set prices adequate to ensure energy resources to meet its reliability responsibilities.”).
21 Regulators have good reason to cap prices, and no regulator has expressed any interest in eliminating offer caps. As explained in Section III.C, offer caps limit market power, reduce volatility, and temper the challenges of demand inelasticity.
creates a need for administrative interventions to ensure full cost recovery and prevent these resources from retiring. This is the “missing money problem.”

The distinctive cost profile of renewables exacerbates the missing money problem. In a payment system based on marginal costs, generators recover their fixed costs in those periods when the clearing price exceeds their marginal cost of production. That system requires that the marginal bidder bid into the market at a level that exceeds zero with sufficient frequency for generators to recover their fixed costs and make a profit. When traditional fossil fuel generators set the clearing price, resource adequacy can be maintained through limited interventions that give peaking plants additional revenue. But this is not the case when renewables provide a large percentage of electricity. While zero-carbon emitting generators have substantial capital costs, their marginal costs are extremely low. They therefore bid into the market at, or at least near,
zero.29 As renewables provide an increasing share of total capacity, they suppress energy market clearing prices.30 Price suppression makes it difficult for all generators to cover their fixed costs and drives high-marginal-cost generators such as coal and nuclear power plants out of business.31

Academics have worried about and debated the missing money problem for years.32 Recently, a group of energy economists showed that increasing volumes of renewables threaten to prevent wholesale electricity markets from providing sufficient revenue for prospective entrants to cover their fixed costs.33 Grid operators throughout the country have acknowledged that price suppression caused by renewables prevents energy markets from supporting resource adequacy.34 As a result, regulators have devised other mechanisms to maintain reserves.35

This Article’s contribution is therefore not to diagnose the existence of the missing money problem. It is to (a) show that the problem results not from economic fundamentals, but from a regulatory apparatus that compensates generators based on the marginal costs of the marginal generator; (b) emphasize that renewables exacerbate the missing money problem; (c) explain how regulatory responses to this problem, which date

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29 See id.
31 See infra Section II.C.
34 See, e.g., ISO New England, The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future 1 (June 2015) (unpublished discussion paper), https://www.iso-ne.com/static-assets/documents/2015/06/iso_ne_capacity_mkt_discussion_paper_06_03_2015.pdf [https://perma.cc/X2MC-YA7D] (“[R]enewable resources . . . put downward pressure on energy-market prices . . . . The capacity market will help balance the revenue needs for resources as the energy market provides fewer opportunities for resources to recover their fixed costs.”).
35 See, e.g., id. at 3 (reporting that increasing the number of wind and solar generators may “be expected to increase the price of reserves[] and the revenues of flexible, reserve-providing resources”).
back to at least 2006, are reviving the problems generally associated with rate regulation; (d) show that these interventions favor fossil fuel generators, counteract state clean energy policies, and hinder renewable development; (e) argue that recent regulatory responses illegally intrude on states’ authority over generation facilities; and (f) propose an alternative system that would avoid these problems.

Price suppression in energy markets has induced regulators to intervene to make sure that the generators perceived to be critical to reliability are able to recover their costs. In exchange, these generators agree to provide services for a predetermined time period. These are the hallmarks of utility rate regulation, yet these arrangements are occurring in parts of the country that are thought to have abandoned this form of regulation decades ago. As in rate regulation, and for reasons discussed in Part IV, these administrative interventions prevent consumers from using resources with characteristics they prefer, counteract state renewable policies, favor incumbents, reduce incentives to innovate, and force consumers to pay billions for capacity they do not need.

In this way, the current response to the missing money problem undermines the principles of competition that regulators claim to be protecting.

These administrative interventions have stretched FERC’s jurisdictional authority past its breaking point. FERC has justified interventions to support fossil fuel generators by appealing to section 205 of the Federal Power Act, which permits the Commission to regulate rates so as to ensure “the integrity of the market.”

FERC’s justifications for these interventions have shifted over time, though the Commission generally defends decisions to subsidize incumbent fossil fuel generators on the ground that such subsidies are necessary to maintain market principles. It has, for example, claimed that interventions protect “investor confidence” and market integrity. See, e.g., Calpine Corp., 163 FERC ¶ 61,236 (June 29, 2018) (Glick, Comm’r, dissenting), slip op. at 3-6 & n.6 (critiquing the majority for failing to define its “new standard, the ‘integrity’ of the market”); ISO New England, Inc., 162 FERC ¶ 61,205 (Mar. 9, 2018) (Glick, Comm’r, dissenting in part and concurring in part), slip op. at 4-5 (questioning whether FERC is responsible for ensuring “investor confidence” and, if so, whether FERC should support fossil fuel investors at the expense of renewables investors). More recently, the Commission has argued that administrative pricing “is necessary” to protect “the competitiveness of the PJM capacity market” and to counteract state policies that the Commission perceives to be “disruptive to competitive wholesale market outcomes.” Calpine Corp., 169 FERC ¶ 61,239, slip op. at 5-6 (Dec. 19, 2019); see also Calpine Corp., 171 FERC ¶ 61,035, slip op. at 48 (Apr. 16, 2020) (stating that administrative interventions “protect the integrity of federally-regulated markets against state policies”).
Act (FPA), which charges the Commission with ensuring that wholesale energy sales are “just and reasonable.”\textsuperscript{40} However, the FPA prohibits FERC from exercising jurisdiction over generation resources and gives that authority to the states.\textsuperscript{41} When the D.C. Circuit upheld FERC’s authority to manage grid reliability, it clarified that FERC must leave room for “[s]tate and municipal authorities . . . to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission.”\textsuperscript{42} Thus, FERC can create a market for reliability but cannot prevent states from determining their resource mixes.

Yet FERC has begun to retain supply by bailing out individual generators and excluding renewables from capacity markets.\textsuperscript{43} In shielding generators from competition, FERC has not only recreated the problems of rate regulation in parts of the grid that are ostensibly competitive, but it has done so by intruding on regulatory authority that has traditionally belonged to the states.\textsuperscript{44} In this way, FERC has upset the careful federalist system Congress created when it limited the Commission’s authority to wholesale sales of electricity.\textsuperscript{45}

Rather than revive rate regulation,\textsuperscript{46} this Article argues that grid operators and regulators should simplify reserve requirements, stop counteracting state clean energy programs, and support the development of competitive markets for capacity. It articulates three principles that would support these goals while respecting the limits of FERC’s authority.

\begin{footnotesize}
\begin{enumerate}
\item See 16 U.S.C. § 824(b)(1) (stating that the Commission “shall not have jurisdiction . . . over facilities used for the generation of electric energy”).
\item See Conn. Dep’t of Pub. Util. Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009).
\item See, e.g., Calpine Corp., 169 FERC ¶ 61,239, slip op. at 3 (Dec. 19, 2009) (directing PJM to administratively reprice state-subsidized resources); Infra Part IV.
\item See Fed. Power Comm’n v. S. Cal. Edison Co., 376 U.S. 205, 214, 215-16 (1964) (stating that the FPA “[drew] a bright line . . . between state and federal [regulatory] jurisdiction” in which states have authority over retail rates and FERC has authority over wholesale rates).
\item Wholesale sales are sales “of electric energy to any person for resale,” which means sales to a person or entity that will sell electricity to consumers. See 16 U.S.C. § 824(d). FERC has authority to make sure that wholesale rates are “just and reasonable,” but the FPA stipulates that states have authority over retail rates and are able to determine their own fuel supply. 16 U.S.C. § 824d(a); see also 16 U.S.C. 824(b)(1) (stating that the Commission “shall not have jurisdiction . . . over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce”); Fed. Energy Regulatory Comm’n v. Elec. Power Supply Ass’n, 136 S. Ct. 760, 767-68 (2016) (describing FERC’s role in the federal system).
\end{enumerate}
\end{footnotesize}
First, grid operators and regulators should rely on competitive forces—not administrative judgments—to determine the value of specific resources. Second, while grid operators can create reserve requirements, they should not force load-serving entities (LSEs)—the companies that purchase electricity from generators and distribute it to consumers—to procure reserves in any particular way or bail out specific generators. Third, rather than counteract state efforts to promote clean energy, central auctions should incorporate price signals generated by state decarbonization policies. Subsidies pervade the electricity sector. It is inexplicable that FERC and certain grid operators regard some state programs as posing a unique threat to the power grid when the energy sector has always been heavily subsidized and when, by one count, sixty-five percent of the one trillion dollars the United States has spent supporting the energy sector since 1950 have gone to fossil fuels.

One possible approach is to shift resource procurement decisions for capacity to LSEs. These entities already must comply with energy market rules, capacity obligations, and state renewable mandates. If LSEs made resource procurement decisions for themselves—rather than purchase capacity from administratively determined auctions—they could balance these various obligations cost-effectively. This approach would encourage LSEs to enter long-term, bilateral contracts to meet fuel security and clean energy laws. Capacity markets would be optional such that LSEs could take advantage of fuel savings generated by a centralized auction but opt out of the capacity market by contracting bilaterally when doing so allows them to fulfill their obligations at lower cost. The role of grid operators would contract. The wholesale market would consist of energy and balancing markets to ensure that electricity is provided at low cost, but it would not be the exclusive mechanism for ensuring resource adequacy. This would allow LSEs to balance their various regulatory obligations. FERC and the grid operators could determine reserve requirements, but LSEs could comply with these requirements by self-supplying with their own generators.

47 FERC and grid operators retain authority to provide out-of-market support for critical suppliers by entering into “reliability-must-run” (RMR) contracts with such generators. These contracts entitle generators to recoup their costs and make a profit by charging ratepayers directly, without entering energy or capacity markets. See, e.g., Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. § 6.1 (Feb. 2, 2018), https://www.pjm.com/directory/merged-tariffs/oapdf [https://perma.cc/6MNJ-Z3H] (establishing certain procedures for “must-run” resources, which, “as a result of transmission constraints, the Office of the Interconnection determines . . . must be run in order to maintain the reliability of service in the PJM Region”); see also Marcy Crane, Stakeholders: ISO-NE Reliability Agreement for Mystic Units A New Frontier’, S&P GLOBAL MKT. INTELLIGENCE (May 24, 2018), https://www.spglobal.com/marketintelligence/en/news-insights/trending/g7jolwarnwrgiaa4yctw2 [https://perma.cc/T4R3-CGVL] (summarizing critiques of one such agreement).

48 Calpine Corp., 163 FERC ¶ 61,236 (June 29, 2018) (Glick, Comm'r, dissenting), slip op. at 6-7.
contracting bilaterally, or transacting on central markets overseen by the grid operators. An energy market, preferably one with high offer caps, would ensure that in any given moment, electricity is provided as inexpensively as possible. Two additional benefits are that this system is more consistent with FERC’s jurisdictional authority, and that it minimizes built-in subsidies to peaking plants.

This Article challenges prevailing views in the legal academy about the federal government’s unwillingness to address climate change. On one side are scholars who have criticized the federal government for failing to take more aggressive steps to reduce carbon emissions. On the other side are those who have identified, and commended, state experimentation that has flourished due to federal inaction. We agree with scholars critical of federal environmental policy, but for different reasons. The problem is not simply that the federal government has missed an opportunity to reduce carbon emissions. It is that other federal programs—in particular, policies designed to ensure reliable electricity—operate at cross-purposes with state clean energy programs.

Moreover, while we agree with commentators who have celebrated state renewable policies, we do not share their optimism that federal inaction is encouraging states to develop creative solutions to climate change. Granted, states have stepped into the void left by the federal government and come up with innovative policies that promote low-carbon technologies, but this experimentation is at the mercy of federal energy regulations that can prevent state policies from driving a large-scale transition to renewables.

49 Energy markets give natural gas a built-in hedge against gas price volatility. See infra Section IV.D.


52 See Ann E. Carlson, Iterative Federalism and Climate Change, 103 NW. U. L. REV. 1097, 1100 (2009) (explaining that although the “national government has failed to lead on climate change regulation,” states have been active in regulating carbon emissions).
These questions have enormous implications for the United States' ability to integrate the level of renewables necessary to avoid the worst effects of climate change. The DOE's proposed coal and nuclear power plant bailout was widely criticized for impeding state efforts to integrate higher volumes of renewables. What has gone largely unnoticed is that the interventions described in this Article possibly amount to a larger handout to fossil fuel companies. According to one estimate, recent reforms to PJM's capacity market alone could cost ratepayers more than the proposed coal and nuclear bailout would have, and PJM provides electricity to only around sixty-five million Americans.

The central question this Article takes up is whether it is legally and economically feasible to preserve competition in electricity markets while integrating higher volumes of renewables, or whether more radical reform is necessary. As this Article shows, the current structure for compensating generators may be ill equipped to the cost structure of renewables, but recent regulatory responses amount to a handout to favored fossil fuel generators. This Article argues that competitive electricity markets can accommodate state resource preferences and support grid reliability even with high levels of renewables, and they can do so without counteracting state energy programs.

This Article proceeds in six Parts. Part I provides a brief history of American electricity markets. Part II describes the transition to a market-based approach and explains how the current payment system creates a missing money problem. Part III explains how increased penetration of renewables exacerbates the missing money problem and describes regulatory responses. Part IV argues that these responses recreate the problems

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55 WHO WE ARE, supra note 1.

56 See Boyd, supra note 51, at 1620 (“[A] revitalized notion of public utility . . . could play an important role in the effort to secure a low-carbon future.”).
associated with rate regulation. Part V argues that these interventions exceed FERC’s jurisdictional authority. Part VI considers reforms.57

I. HISTORY AND STRUCTURE OF THE ELECTRICITY INDUSTRY

This Part provides a history of energy regulation from the nineteenth century until restructuring began in the 1990s. Over this period, the belief that electricity was a natural monopoly contributed to regulatory decisions to shield suppliers from competitive forces.58 This regulatory approach was successful at providing reliable electricity, but it left little incentive for generators to innovate and control costs. This Part presents a background on electricity regulation and highlights the shortcomings of cost-of-service regulation. Part IV argues that regulatory responses to the missing money problem are recreating the drawbacks associated with that approach.

A. Early History of the Electricity Industry

Whenever someone turns on her lights, a complex technological and regulatory apparatus allows electricity to flow instantaneously into her home. That apparatus is supported by three components: generation, transmission, and distribution.59 Generation is the process of converting fuels or renewable resources into electricity at central power stations.60 Transmission refers to the transportation of electricity across large distances at high voltages.61 The distribution system consists of low-voltage networks that circulate electricity to end-users.62

For most of the industry’s 140-year history, vertically integrated utilities provided electricity to customers at regulated rates. This model extends back to the 1880s when the technological innovations of Thomas Edison, George Westinghouse, and others made widespread use of electricity possible.63

57 This Article focuses on regulatory barriers to a clean energy grid. Technological constraints also prevent renewables from providing one hundred percent of American electricity. Note, however, that the system we propose compensates generators only for the services they provide. Thus, our proposal would ensure that resources needed for reliability—including fossil fuels—operate when they are needed.

58 See KAHN, supra note 16, at 11 (listing “[t]he importance” of the utility industries, the view that these industries are “natural monopolies” and the belief that “competition simply does not work well” as the three basic economic justifications for utility rate regulation).


60 See id.

61 See id.

62 See id.

decision to regulate utilities was based on the economic view that the provision of electricity was a natural monopoly—that there were economies of scale such that long-run average costs declined as production increased.64 This meant that the cost-minimizing arrangement for society was for a single large firm to meet all of a region’s electricity needs.65

One of Edison’s lieutenants, Samuel Insull, designed the original utility business strategy while he was president of the Chicago Edison Company.66 Insull pioneered and advocated for a regulatory approach based on two principles. First, electric power utilities should be vertically integrated.67 The utility should own the central power stations where electricity is generated, the wires used to transmit that electricity, and the meters which measure sale to customers.68 As Insull wrote in an 1898 speech to his industry colleagues, “the best service at the lowest possible price can only be obtained . . . by exclusive control of a given territory being placed in the hands of one undertaking.”69

Second, electric power utilities should be established as regulated monopolies.70 In each region, the government would allow only one utility to operate.71 In exchange, the utility must serve all customers in the region on a nondiscriminatory basis and at regulated rates.72 Recognizing the need to prevent predatory pricing, Insull acknowledged that “exclusive franchises should be coupled with the conditions of public control requiring all charges

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64 See Boyd, supra note 51, at 1638-39 (2014) (explaining that the utility industries shared characteristics that created what “economists since the late nineteenth century had referred to as ‘natural monopoly’” and that “[r]ate regulation . . . provided an alternative means of regulating those sectors of the economy that were seemingly beyond the full reach of the antitrust laws”). Others have pointed out that rate regulation reduced the cost of capital and thus facilitated the development of capital-intensive costs projects that might otherwise struggle to fund their operations. See William J. Hausman & John L. Neufeld, The Market for Capital and the Origins of State Regulation of Electric Utilities in the United States, 62 J. ECON. HIST. 1050, 1069 (2002) (arguing that “a primary reason utility companies, with prominent leaders such as Samuel Insull leading the way, came to embrace regulation” was that it “reduced borrowing costs”).

65 See EISEN ET AL., supra note 63, at 62-66 (explaining the economic theory underlying the model of a natural monopoly).

66 Id. at 32-37 (quoting PLATT, supra note 63, at 66-91).

67 See Samuel Insull, President, Nat’l Electric Light Ass’n, Address at the Twenty-First Convention of the National Electric Light Association (June 7, 1898), in PROCEEDINGS OF THE NATIONAL ELECTRIC LIGHT ASSOCIATION: TWENTY-FIRST CONVENTION 14, 26-27 (1898).

68 See EISEN ET AL., supra note 63, at 62-63 (explaining why it is more efficient for one firm to bear all of these costs within one system).

69 See Insull, supra note 67, at 27.

70 Id.

71 Id.

72 See Horace M. Gray, The Passing of the Public Utility Concept, 16 J. LAND & PUB. UTIL. ECON. 8 (1940), reprinted in 5 J. REPRINTS ANTITRUST L. & ECON. 481, 488 (1973) (“Certainly many of the proponents of public utility regulation intended it to protect consumers against excessive charges and discriminations; all the early state laws bear witness to this intent.”).
for services fixed by public bodies to be based on cost, plus a reasonable profit.”73 The utility was permitted to charge rates that would permit it to recover its costs and make a profit: by the end of the twentieth century, a return on equity of roughly six to ten percent.74 Both the federal government and the state governments played a role in rate-setting. FERC set rates for interstate transmission and wholesale electricity sales.75 State governments, through their public utility commissions (PUCs), set rates for distribution and retail electricity sales.76 The Federal Power Act of 1935 established these jurisdictional boundaries.77

This arrangement—privately owned utilities operating a monopoly under public supervision and rate-setting—was the dominant paradigm for most of the electric power industry’s history.78 This form of regulation is known as “cost-of-service regulation” or “rate regulation.”79 Insull’s model persisted for much of the twentieth century.80

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73 Id.
75 See 16 U.S.C. § 824(b) (2018) (giving FERC jurisdiction over “the transmission of electric energy in interstate commerce” and “over all facilities for such transmission or sale of electric energy”).
76 EISEN ET AL., supra note 63, at 83 (“[R]etail sales of energy and power distribution and generation facilities are regulated by states.”); see also 16 U.S.C. § 824(a)–(b)(1) (limiting federal jurisdiction of energy sales to wholesale sales, leaving the regulation of retail sales of energy and power distribution and generation facilities to states). Wholly intrastate transmission also falls under state jurisdiction, but only exists in Texas, Alaska and Hawaii. See, e.g., ERCOT, PTD. ENERGY REG. COMMISSION, https://www.ferc.gov/industries/electric/indus-act/rr/ercot.asp [https://perma.cc/HXD2-P65M] (last visited May 15, 2020) (“The transmission grid that the ERCOT independent system operator administers is located solely within the state of Texas and is not synchronously interconnected to the rest of the United States. The transmission of electric energy occurring wholly within ERCOT is not subject to the Commission’s jurisdiction under sections 203, 205, or 206 of the Federal Power Act.”).
79 See Severin Borenstein & James Bushnell, The US Electricity Industry After 20 Years of Restructuring, 7 ANN. REV. ECON. 437, 438 (2015) (describing the pre-1990s system of “cost-of-service regulation, in which utilities were effectively guaranteed the recovery of prudently incurred operating costs plus a regulated return on capital expenditures”).
80 See PAUL L. JOSKOW & RICHARD SCHMALENSEE, MARKETS FOR POWER: AN ANALYSIS OF ELECTRIC UTILITY Deregulation 11-13 (1985) (“[T]he overriding principle of state rate...
B. Competition in Electricity Markets

A number of political, technological, and theoretical changes in the 1970s, 1980s, and 1990s undermined the natural monopoly model. This Section first describes the scholarly critiques that provided the theoretical basis for introducing competition into power generation. As Part IV argues, those critiques have taken on renewed salience as FERC has assumed an increasingly interventionist role in determining which generators enter and exit the market. This Section also describes the political, technological, and legal developments that supported restructuring.

1. Theoretical Challenges to the Natural Monopoly Model

Developments in economic theory in the latter half of the twentieth century provided important intellectual support for restructuring. In the 1960s, a deregulatory movement emerged to challenge the belief that generation should be regulated as a natural monopoly. These critiques emphasized that shielding corporations from competitive forces reduced innovation, weakened incentives to keep costs down, led to excess capacity, and limited consumer choice.

a. High Prices and Excess Capacity

In 1962, Harvey Averch and Leland Johnson provided a groundbreaking analysis of rate regulation. Now known as “gold plating” or the Averch–Johnson effect, they formalized the intuition that regulated utilities make

regulation is that utilities should be allowed to cover the cost, prudently incurred, of providing service, including a fair rate of return on investment . . . . The difficulties that this regulatory process seems to have in achieving these objectives . . . seems to be a primary motivation for recent proposals for structural and regulatory reform.”; Dieter Helm & Tim Jenkinson, Introducing Competition into Regulated Industries, in COMPETITION IN REGULATED INDUSTRIES 1, 2 (Dieter Helm & Tim Jenkinson eds., 1998) (“The concept of supply competition has caught on in Europe and the USA . . . . In the USA . . . the 1992 Energy Act and the subsequent order 888 by [FERC] provided for the transition to a more competitive electricity supply market, at least at the wholesale level.”).


83 See W. Davis Dechert, Has the Averch-Johnson Effect Been Theoretically Justified?, 8 J. ECON. DYNAMICS & CONTROL 1, 1 (1984) (describing ‘the Averch-Johnson effect,’ in which ‘a monopoly subject to a rate of return (to capital) constraint would not use a cost-minimizing input mix, but rather it would overcapitalize’).
excessive capital investments to increase their profits. This behavior turns out to be a rational response to rate regulation. In a typical rate case, regulators determine the firm’s revenue requirement, which is based on the costs the firm incurs in providing services. So long as a utility can convince regulators that a capital investment is needed to maintain a reliable power grid—and utilities are generally better informed about their costs than regulators—then the costs of the investment will fall on ratepayers. While regulators may try to determine whether a particular asset is necessary, once a firm receives regulatory approval to make a capital investment, it enjoys a right to recoup its costs plus a return by charging ratepayers.

This incentive structure encourages regulated utilities to build excess capacity even when they might achieve the same goals in less costly ways. A utility might, for example, create incentives for consumers to reduce their electricity consumption, but doing so will not increase—and might reduce—the amount of capital the utility needs. As a result, these strategies lower the utility’s rate base and depress revenues. A utility will therefore prefer to increase its rate base despite the existence of more efficient alternatives.

b. Innovation

Equally problematic is that rate regulation makes firms hesitant to innovate. In ordinary markets, when a company’s business model is predicated on outperforming its competitors, it has an incentive to invest in research and development (R&D). Companies in technology-dependent

84 See Averch & Johnson, supra note 81, at 1052-59.
85 See Paul L. Joskow, The Determination of the Allowed Rate of Return in a Formal Regulatory Hearing, 3 BELL J. ECON. & MGMT. SCI. 632, 633-34 (1972) (detailing the difficulties faced by public utilities commissions in ascertaining a rate of return without access to information about capital costs and the tradeoffs faced by an individual firm).
86 See Catherine Wolfram, The Efficiency of Electricity Generation in the United States After Restructuring, in ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES 227, 235 (James M. Griffin & Steven L. Puller eds., 2003) ("[G]iven the input costs, firms choose the mix of inputs that minimizes the costs of producing a given level of output . . . . [F]uel adjustment clauses allow utilities to pass through to ratepayers all of their fuel costs, so they have little incentive to minimize the amount of fuel they burn to generate a given amount of electricity.").
87 See Smyth v. Ames, 171 U.S. 361, 363 (1898) (establishing that regulated industries have a right to "reasonable compensation" for costs); accord Fed. Power Comm’n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944) ("[T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated . . . . That return . . . should be sufficient to assure confidence in the financial integrity of the enterprise.").
88 Cf. Wolfram, supra note 86, at 235 ("Firms facing more competition might move closer to the technological frontier by figuring out how to generate the same amount of electricity with fewer inputs.").
89 See Toshihiro Matsumura, Noriaki Matsushima & Susumu Cato, Competitiveness and R&D Competition Revisited, 31 ECON. MODELLING 541, 546 (2003) (finding that firms in monopolistic and highly competitive markets spend more on R&D than firms in oligopolistic markets).
industries such as pharmaceuticals and computer manufacturing often spend ten to twelve percent of their total revenue on R&D. Even industries that depend less heavily on technological innovation spend on average between three and five percent of total revenues on R&D. Utilities, however, are unique. Most investor-owned energy utilities have historically spent far less than that.

Investor-owned utilities’ reluctance to spend on R&D can be understood to be at least in part a natural consequence of rate regulation. In a competitive market, a company that develops a new technology may capture market share from its competitors. A utility, however, faces little upside for innovating because it already controls its entire market and therefore cannot expand by developing new technologies that allow it to offer better service than its rivals.

In fact, utilities may even be punished for spending money on R&D. Utilities are often allowed to include only “prudent” investments in their rate base. If a regulator determines that a utility should not recover the costs of a research project, it can force the utility’s shareholders—rather than its ratepayers—to bear those costs. In this way, not only does rate regulation eliminate the potential benefits of R&D, but it introduces the additional risk of a regulator deciding that a particular project does not serve a useful purpose.


91 See id. (noting R&D expenditures for manufacturers and nonmanufacturers).

92 See Marilyn Waite, Why US Utilities Should Invest in Innovation, UTIL. DIVE (Apr. 24, 2017), https://www.utilitydive.com/news/why-us-utilities-should-invest-in-innovation/444114 [https://perma.cc/89HD-JH9D] (“The research and development (R&D) budgets of U.S. electric utilities—both POUs and IOUs—tend to be slim, and in many cases near zero. Historically, the maximum that an electric utility in the United States would spend on R&D is 1% of its revenue—but . . . most investor-owned utilities spend 0%.”).

93 See U.S. GEN. ACCOUNTING OFFICE, GAO-RCED-96-201, FEDERAL RESEARCH: CHANGES IN ELECTRICITY-RELATED R&D FUNDING 6 (1996), https://www.gao.gov/archive/1996/rc96203.pdf [https://perma.cc/E8WW-KRSM] (finding that only 6 of 112 investor-owned utilities surveyed devoted 1% of revenues to R&D, which was the proportion recommended by the National Association of Regulatory Utility Commissioners). Note, though, that highly competitive market conditions can also lead to a decline in R&D spending in the electricity industry. See id. at 7 (“Increased competition was cited as the primary reason for the biggest cutbacks to date by utilities in California, New York, and Florida . . . . [T]hey are under pressure to cut costs in order to be able to compete in a deregulated market.”).


95 See id. at 315-16 (permitting PUCs flexibility to exclude certain costs from the utility’s rate base).
c. Consumer Choice

Finally, rate regulation limits consumer choice. In competitive systems, a consumer can look for products with idiosyncratic qualities she prefers. For example, some coffee drinkers purchase fair-trade coffee and are willing to pay extra to support humane work conditions. In rate-regulated markets, regulators decide which products will be available to consumers. If a utility does not procure renewables, consumers may not be able to purchase clean energy. This problem is newly relevant as states and LSEs attempt to allow consumers to procure electricity from clean energy sources. As Part IV shows, capacity market interventions and cost-of-service agreements threaten to prevent renewable-friendly states from realizing their preference for zero-carbon energy.

These problems—that utilities overestimate costs, make excessive capital investments, refuse to innovate, and do not accommodate consumer preferences—are exacerbated if a regulated firm “captures” its regulators. Absent competition, firms will allocate resources that might have been spent trying to outperform their rivals currying regulatory favor. When a highly regulated industry works closely with its regulators over a long period of time, the industry will have ample opportunity to develop strong relationships with regulators. Insofar as a firm is able to convince regulators to be sympathetic to its interests, it will be easier for the firm to convince regulators to approve favorable rates.

2. Political and Technological Changes

The academic movement described in the previous subsection coincided with—and offered theoretical justification for—legal, political, and

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96 See Richard A. Posner, Natural Monopoly and Its Regulation, 21 STAN. L. REV. 548, 666-68 (1969) (discussing rate categories and their effects on the availability of products such as subsidized railroad services).

97 See Ernesto Dal Bó, Regulatory Capture: A Review, OXFORD REV. ECON. POL’Y 203, 211-17 (surveying literature on regulatory capture and summarizing the view that regulation encourages firms to allocate funds on lobbying).

98 There is a voluminous literature analyzing the strategies utilities adopt to convince regulators to give more weight to their interests. See, e.g., Jean-Jacques Laffont & Jean Tirole, The Politics of Government Decision-Making: A Theory of Regulatory Capture, 106 Q.J. ECON. 1089 (1991) (applying principal-agent theory to show that regulatory capture will lead to inefficient investment outcomes in regulated industries); Mathew D. McCubbins, The Legislative Design of Regulatory Structure, 29 AM. J. POL. SCI. 721, 723 (1985) (describing how legislative delegation to administrative agencies can lead to indirect regulation).

technological changes that led to the deregulation of electric power generation in much of the United States. ¹⁰⁰

Technological developments that made designs for natural gas power plants cost-competitive in the 1980s were critical to the development of competitive markets. ¹⁰¹ Because these facilities were smaller and less expensive than traditional coal and nuclear power plants, it was possible for small, non-utility players to build and operate them. ¹⁰² However, delivery of electricity—the service of transmitting and distributing electricity from generators to end-users—continued to be seen as a natural monopoly because it was inefficient to construct duplicate transmission lines. ¹⁰³

An early step toward restructuring occurred in 1978 with the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA). ¹⁰⁴ In an effort to reduce the United States’ reliance on imported oil, ¹⁰⁵ Congress passed PURPA in part to encourage domestic development of renewable and other nontraditional power plants. ¹⁰⁶ The law mandated that vertically integrated utilities allow renewable and cogeneration power plants ¹⁰⁷—called “qualifying facilities” (QFs)—to interconnect to the power grid. Utilities had to purchase electricity generated by the QFs at “avoided cost,” which is the amount it would cost for a utility to generate that electricity itself. ¹⁰⁸ The Act

¹⁰⁰ Note that most of the technological advances that supported restructuring occurred not because of research supported by the utilities, but by adapting technologies developed for other industries. See Borenstein & Bushnell, supra note 79, at 2-3 (identifying the “critical exogenous trend[.]” during the deregulation period of adopting technology from other sectors, as affecting the “relationship between average and marginal cost in the industry”).

¹⁰¹ See id. at 2.

¹⁰² See GILBERT M. MASTERS, RENEWABLE AND EFFICIENT ELECTRIC POWER SYSTEMS 6-7 (2d ed. 2013) (discussing the effects of this technological change in conjunction with regulatory changes that also facilitated the operation of “small, on-site generators”).

¹⁰³ See id. at 2.


¹⁰⁶ See id.; see also Public Utility Regulatory Policies Act (PURPA), UNION OF CONCERNED SCIENTISTS (July 15, 2002), https://www.ucsusa.org/resources/public-utility-regulatory-policy-act [https://perma.cc/85WM-23W4] (“PURPA has been the most effective single measure in promoting renewable energy.”)


¹⁰⁸ MASTERS, supra note 102, at 7.
demonstrated that utilities could transmit and distribute electricity purchased from independent producers.

Three regulatory initiatives in the mid-1990s continued this deregulatory trend. First, Congress enacted the Energy Policy Act of 1992, which expanded the number of independent facilities that could generate electricity. Specifically, the Act allowed “exempt wholesale generators,” which could be of any size and use any fuel, to connect to the grid and sell to utilities. The Energy Policy Act of 1992 led to the proliferation of independent power producers (IPPs) and exempt wholesale generators (EWGs), terms that refer to non-utility companies that build, own, and operate generators. IPPs were often newly developed natural gas power plants that sold their electricity to utilities. Unlike vertically integrated utilities, IPPs did not enjoy a guaranteed rate of return.

Shortly after the Act’s passage, FERC issued Orders 888 and 2000, which ordered utilities to separate generation and transmission functions and encouraged the formation of independent system operators (ISOs) and regional transmission organizations (RTOs). These nonprofit entities, known as “grid operators,” manage transmission facilities. FERC wanted

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110 See MASTERS, supra note 102, at 8.
111 See id. at 6, 8.
112 See id. at 8 (explaining that IPPs “are subject to different regulatory constraints than traditional utilities” and instead have “pre-negotiated contracts with customers in which the financial conditions for the sale of electricity are specified by power purchase agreements”).
115 See Electric Power Markets, FERC, https://www.ferc.gov/market-assessments/mkt-electric/overview.asp [https://perma.cc/XP3G-EB3K] (last visited Feb. 11, 2020) (“Along with facilitating open-access to transmission, ISOs operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants.”). ISOs and RTOs serve similar functions. ISOs are the entities that were established after Order 888. RTOs were established in response to Order 2000. As one account of their creation explains:

FERC first created ISOs with Order 888, which established open-access interstate transmission policy. FERC later refined these concepts with Order 2000, which created RTOs more specifically. Some market operators qualify as both an ISO and an RTO; the names currently in use typically reflect the initial origin of the operators’ formation. (i.e., in response to Order 888 or Order 2000), rather than any particular legal or organizational function.
grid operators to control transmission lines in order to prevent transmission line owners from keeping IPPs from accessing the grid.\textsuperscript{116}

II. RESTRUCTURING AND THE MISSING MONEY PROBLEM

The regulatory, technological, and theoretical developments described in the previous Part set the stage for a large-scale industry restructuring, which took place across a number of states in the late 1990s and early 2000s.\textsuperscript{117}

Once Order 888 required vertically integrated utilities to separate generation from transmission, a number of utilities created or joined competitive markets for electricity generation. Rather than pay power plants through rates set by regulators, compensation for generation in those regions with competitive markets occurs through a bidding process.\textsuperscript{118} A grid operator—an ISO or RTO—manages each market subject to FERC oversight.

Sever seven competitive generation markets formed in the late 1990s.\textsuperscript{119} These

Danny Cullenward & Shelley Welton, The Quiet Undoing: How Regional Electricity Market Reforms Threaten State Clean Energy Goals, 39 YALE J. ON REG. BULLETIN 106, 109 n.16 (2019). For ease of understanding, we refer to grid operators as RTOs.

\textsuperscript{116} See Borenstein & Bushnell, supra note 79, at 6 (discussing the shift in compensation for generation from a “cost-of-service regulation model” to a “market-based pricing model”). Restructuring focused on power generation. Reformers still viewed transmission as a natural monopoly. Distribution also remained subject to state rate regulation, though a number of states have also attempted, with varying degrees of success, to introduce competition into retail markets.

\textsuperscript{117} See id. at 2, 6-7.


markets are displayed in Figure 1. As of 2018, two thirds of electricity generated in North America originates in regions overseen by an ISO or an RTO.120

Figure 1: ISOs and RTOs in the United States121

Generators generally receive revenues from three different markets. The primary source of generator revenue is—or at least is supposed to be—the energy market.122 Generators use energy markets to make bids that are

120 See Borenstein & Bushnell, supra note 79, at 6-7. The Northwest and Southeast enjoyed low wholesale electricity prices in the mid-1990s and so did not feel the same pressure to restructure. See Electric Power Markets, supra note 115 (indicating that “[t]raditional wholesale electricity markets” still operate in these areas).


cleared in a day-ahead market and in real time. In addition, all markets except Texas have some sort of resource adequacy requirement. As discussed in Section III.A, these requirements developed because the energy markets were not providing sufficient revenues to support generators needed for reliability. Some grid operators, such as MISO and CAISO, allow LSEs to determine for themselves how to comply with resource adequacy requirements. ISO-NE, NYISO, and PJM, by contrast, have developed centrally administered capacity markets in which they procure capacity on behalf of LSEs. Finally, ancillary services markets allow operators to maintain a minimum reserve margin through regulated planning, resource adequacy requirements, or capacity markets.). ERCOT uses scarcity pricing, which can be understood as a form of resource adequacy requirement.


See SAMUEL NEWELL ET AL., BRATTLE GRP., ERCOT INVESTMENT INCENTIVES AND RESOURCE ADEQUACY 11 (2012), https://hepg.hks.harvard.edu/files/hepg/files/brattle_ercot_resource_adequacy_review_-2012-06-01.pdf ("ERCOT’s design as an energy-only market distinguishes it from all other regions in the U.S. Other U.S. markets maintain a minimum reserve margin through regulated planning, resource adequacy requirements, or capacity markets."). ERCOT uses scarcity pricing, which can be understood as a form of resource adequacy requirement.
procure various services that help smooth grid operation, including reserves and frequency regulation.128

A. Energy Markets

Today, generators derive most of their revenues from the energy market,129 though in some regions, capacity markets have begun to determine which generators enter and exit the market.130 The energy market matches available electricity resources to demand. The actual goods sold are megawatt-hours (MWh) of electrical energy.131 Each power plant regularly submits a bid (in dollars per megawatt-hour) to supply an amount of energy (in megawatt-hours) for a given time period. A plant’s bid represents the price at which the plant is willing to supply energy to the power grid.132

Energy markets operate according to a principle called merit order dispatch. For every market period, grid operators collect bids from all available resources and order them from lowest cost to highest cost.133 Grid operators also observe total demand for each market period.134 Starting with the least expensive power plant, a grid operator clears resources until all specific amount of capacity commitments from power plants and other resources. The other three RTOs designed their auctions with an administratively defined, sloped demand curve that, combined with offers from owners of . . . resources, determines the specific amount and price of capacity commitments . . . 


129 See, e.g., PJM, ENERGY PRICE FORMATION AND VALUING FLEXIBILITY 2 fig.1 (2017), http://www.pjm.com/-/media/library/reports-notices/special-reports/20170515-energy-market-price-formation.ashx [https://perma.cc/RDSK-8JBS] (showing that energy markets supply the majority of revenue in PJM but that capacity markets have taken on a larger role in recent years).

130 Capacity markets now account for nearly a quarter of total revenues in some markets. See 2018 PJM STATE OF THE MARKET REPORT, supra note 122, at 16 (stating that capacity markets accounted for $10.3 billion of generator revenues in 2018, while total generator revenues amounted to $41.4 billion (subtracting transmission payments and administrative fees from total price), such that the capacity share is 24.9%). As of 2018, that number was nearly thirty percent in ISO-NE. See ISO NEW ENG., 2018 ANNUAL MARKETS REPORT 4-5 (2019), https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf [https://perma.cc/K2AJ-XTXT].

131 Two of the main quantities measured in electricity are energy and power. Energy is the ability to do a useful task, such as boil a gallon of water or keep a room lit for an hour, and is measured in watt-hours (Wh), kilowatt-hours (kWh), and megawatt-hours (MWh). Power is the flow of energy over time and is measured in watts (W), kilowatts (kW), and megawatts (MW). For example, a 60-watt bulb requires 60 watts of power to provide light. If the bulb lights a room for an hour, it uses 60 watt-hours of energy.


133 See id.

134 See id.
demand can be met.135 Clearing—also known as dispatching—a resource entails directing that resource to supply power at its bid level for the entire period.136 The marginal generator is the last resource dispatched to meet demand in a period.137 Resources that submit bids that are more expensive than that of the marginal generator are directed not to supply power for that period.138 The market clearing price is set by the marginal generator’s bid.139 All dispatched plants receive payments equal to the market clearing price (in dollars per megawatt-hour) multiplied by the amount of energy (in megawatt-hours) they supply during the market period.140

Merit order dispatch incentivizes each generator to submit bids equal to its marginal costs.141 Marginal costs are the costs incurred in generating electricity after a power plant has been built and is ready for operation.142 Generally, these costs include fuel costs, variable operations and maintenance (O&M) costs, and any emissions costs.143 They do not include the amortized construction costs for the plant. Nor do they include fixed O&M costs, which are operating costs that do not depend on the amount of electricity generated, such as plant security and insurance.144

Under this system, it is profit-maximizing for power plants to bid their marginal costs. A generator that bids at less than its marginal costs risks being dispatched when the market clearing price is insufficient to cover its costs and operating at a loss. A generator bidding above marginal costs risks not being dispatched even when it would be profitable for the plant to provide electricity at that price.

Table 1 presents marginal costs for a range of resources and fuel types. Figure 2 is a representative view of the merit order on a U.S. power grid. As the graph shows, either an old natural gas power plant or a coal power plant

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135 See id.
137 See id. (discussing “how economic dispatch and the uniform clearing price work together” (capitalization altered)).
138 Id.
139 See id. (“The energy price to be paid to all resources meeting demand is set by the resource in the supply stack that would satisfy the next increment of energy needed if demand were to increase.”).
140 Id.; see also Udi Helman, Distributed Energy Resources in the U.S. Wholesale Markets: Recent Trends, New Models, and Forecasts, in CONSUMER, PROSUMER, PROSUMAGER: HOW SERVICE INNOVATIONS WILL DISRUPT THE UTILITY BUSINESS MODEL 431, 454 (Fereidoon Siohansi ed., 2019) (“Wholesale energy markets allow for generators and storage resources to obtain payments ($/MWh) for all their energy (real power) production delivered to the bulk power system.”).
142 See id. at 12-13.
143 See id.
144 Id.
usually sets the market clearing price in periods of moderate demand. During periods of peak demand, a natural gas peaking plant usually sets the market clearing price.\textsuperscript{145} A power plant’s operating profit in a period is the difference between the market clearing price and the plant’s marginal cost, multiplied by the megawatt hours generated in that period.

### Table 1: Representative Marginal Costs for Electric Power Generators\textsuperscript{146}

<table>
<thead>
<tr>
<th>Generator Type</th>
<th>Approximate Marginal Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>$0 / MWh</td>
</tr>
<tr>
<td>Solar</td>
<td>$0 / MWh</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>$0 - $5 / MWh</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$10 / MWh</td>
</tr>
<tr>
<td>Coal</td>
<td>$15 - $25 / MWh</td>
</tr>
<tr>
<td>Natural Gas Combined Cycle, New</td>
<td>$25 / MWh</td>
</tr>
<tr>
<td>Natural Gas Combined Cycle, Old</td>
<td>$25 / MWh</td>
</tr>
<tr>
<td>Natural Gas Peaking</td>
<td>$35 - $45 / MWh</td>
</tr>
<tr>
<td>Diesel Peaking</td>
<td>$200 / MWh</td>
</tr>
</tbody>
</table>

\textsuperscript{145} See MASTERS, supra note 102, at 137, 144.

\textsuperscript{146} LAZARD, LAZARD’S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 10.0, at 18-20 (2016), https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf [https://perma.cc/68ZJ-AG8B]; U.S. ENERGY INFO. ADMIN., LEVELIZED COST AND LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2017, at 7 (2019), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf [https://perma.cc/S5YF-4MWQ]. Marginal cost for each generator type is calculated by adding together “Variable O&M” and the product of “Heat Rate” and “Fuel Price” divided by 1000. See LAZARD, supra, at 18-20 (using these labels). Values are approximate and rounded to the nearest $5, reflecting that these values will vary geographically and over time.
Energy markets are effective at ensuring the preferential dispatch of the lowest marginal cost resources, as realized over a short time horizon. Whenever energy is needed, it will be procured at least cost because the market is structured so that the least expensive units are always dispatched before more expensive ones.\footnote{Capacity share for each generator type is based on a rough average of capacity mixes across existing ISOs/RTOs. Marginal costs are based on Lazard and EIA estimates. See supra note 146.}

B. The Missing Money Problem

According to economic theorists, energy markets theoretically should "provid[e] appropriate incentives to stimulate 'adequate' investment in new generating capacity at the right time, in the right places, and using the right
technologies.”

Because energy markets can provide inexpensive electricity while procuring resource adequacy, they theoretically could be the principal basis for determining which generators enter the market and which ones retire. To that end, energy markets create “important opportunities for cost savings . . . associated with long-run investments in generating capacity.”

In practice, however, regulatory interventions prevent energy prices from rising high enough to maintain resource adequacy. Specifically, grid operators cap prices to prevent the market clearing price from rising above set levels. In this way, the entities charged with regulating the grid introduce distortions that prevent energy markets from securing adequate reserves. Thus, while regulators claim that energy markets should—and do—determine which resources will be built and which will retire, they simultaneously recognize that the “energy market does not provide for sufficient revenue to assure reliability given the constraints imposed by offer caps and mitigation, as well as the need to procure capacity above the current demand level.”


150 See William W. Hogan, On an “Energy Only” Electricity Market Design for Resource Adequacy 2 (Sept. 23, 2005) (unpublished manuscript), https://sites.hks.harvard.edu/fs/whogan/Hogan_Energy_Only_092305.pdf [https://perma.cc/gPA9-7HK7] (“In some periods [in energy-only markets] prices would rise above the variable operating costs of peaking units that were running at capacity and would reflect scarcity under constrained capacity with the incremental value of demand defining the system opportunity cost.”); see also Bushnell et al., supra note 24, at 11 (“In a competitive market that satisfies several other conditions, firms will build new capacity as long as the cumulative scarcity rents exceed the cost of capacity. Free-entry would drive the scarcity rents to equal (on average) the cost of new capacity over time.”).

151 Paul L. Joskow, Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector, 11 J. ECON. PERSP. 119, 125 (1997). Another important motivation was to mitigate abusive monopoly practices. See id. at 121 (“Most utilities have historically met their obligations to supply by owning and operating all of the facilities required to supply a complete ‘bundled’ electricity product to retail customers.”); id. at 125 (“The primary stimulus for reform of the U.S. electricity sector is the gap that exists in some parts of the United States between the implicit price of generation services embedded in regulated bundled electricity prices and the ‘unbundled’ price of generation services . . . .”).

152 See Joskow, supra note 149, at 105 (“[FERC] has adopted a variety of general and locational price mitigation measures . . . . These mitigation measures includes general bid caps . . . applicable to all wholesale energy and operating reserve prices, location-specific bid caps . . . , and other bid mitigation and supply-obligation -> measures.”); see also Cramton & Stoft, supra note 32, at 11 (“The missing-money problem is not that the market pays too little, but that it pays too little when we have the required level of reliability.”).

153 See, e.g., PJM INTERCONNECTION, PROPOSED ENHANCEMENTS TO ENERGY PRICE FORMATION 1 (2017), https://www.pjm.com/~member/library/reports-notices/special-reports/20171215-proposed-enhancements-to-energy-price-formation.pdf [https://perma.cc/2U3VH-DFKE] (“PJM Interconnection’s wholesale energy market has driven efficient resource entry and exit, successfully managed the retirement of a significant number of coal resources and their replacement primarily by natural gas resources, and maintained a reliable grid.”).

154 PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, slip op. at 59 (Dec. 22, 2006).
Concerns about the missing money problem have led to numerous regulatory interventions aimed at maintaining sufficient supply. Part IV shows that these interventions have become so intrusive that energy markets no longer determine which resources enter and exit markets in large swaths of the country. This Section first shows that energy markets could conceivably provide revenue adequacy and then shows that offer caps create a missing money problem that requires administrative interventions.


In order to ensure the reliable provision of electricity, supply must be able to meet “peak demand,” which refers to the few periods in the year when demand for electricity is highest. This usually occurs in July or August when people turn on their air conditioning, though in parts of the country with cold winters it occurs in the winter when people turn on their heat.

An important concern is how to incentivize the construction of the last generator needed to meet peak demand. In energy-only markets, a generator’s annual operating profit derives from the difference between the market clearing price and the generator’s marginal cost. A generator runs and makes money only when the market clearing price is above its marginal revenue. Revenue recovery is therefore critical to ensure the reliability of the system.

See, e.g., 2018 PJM STATE OF THE MARKET REPORT, supra note 122, at 49 (“Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of capacity market revenue in covering total costs.”); id. at 29 (“The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.”).

See infra Part IV; see also PJM INTERCONNECTION, supra note 153, at 7 n.5 (“Revenues from the energy and capacity markets were 74.3 percent and 22.9 percent, respectively, of the total generation revenue in 2015, and 71.1 percent and 26.6 percent, respectively, in 2016.”).

See Jonathan Susser, Why Is Peak Demand a Concern for Utilities?, ADVANCED ENERGY (Mar. 13, 2018), https://www.advancedenergy.org/2018/03/13/why-is-peak-demand-a-concern-for-utilities [https://perma.cc/WTL8-KEJU] (“Peak demand is the time when consumer demand for electricity is at its highest; this can be by day, season or year. Peak periods tend to be in the morning during winter months (when lots of heating is occurring) and in the afternoon during summer months (lots of cooling).”).

See id. (“When looking at an entire calendar year in North Carolina, peak demand occurs in the winter.”).

See Gerard Reid, Renewables and the Missing Money Problem, ENERGY & CARBON (Apr. 21, 2015), http://energyandcarbon.com/renewables-and-the-missing-money-problem [https://perma.cc/3Q84-MC89] (“This ‘missing money problem’ comes about because the building of power stations requires significant upfront capital expenditure which needs to be financed through future revenues from power sales. With declining power prices and utilization rates . . . , there is little or no financial incentive to build new capacity.” (emphasis omitted)).

cost. It runs but makes no money when the clearing price equals its marginal cost, which occurs when it is the generator on the margin. And it does not run and makes no money when the clearing price is below its marginal cost. The difference between the clearing rate and an individual generator’s marginal cost comprises the generator’s operating profit for the market period. Annual operating profits in energy-only markets derive entirely from those periods in which the market clearing price exceeds a generator’s marginal cost. This profit is needed to cover the plant’s fixed costs.

While generators bid their marginal costs under ordinary conditions, peaking plants, which bid only when demand is high, are theoretically able to submit above-marginal-cost bids. In most circumstances, a generator risks losing out on profitable bids if it submits a bid above its marginal costs. Peaking plants, however, will be dispatched even if they submit bids well above their marginal costs. Because those generators are the last generators to be dispatched, they do not need to worry that they will be outbid because there are no generators available to outbid them. As a result, peaking plants can drive prices to levels that allow them to recover their fixed costs and make a profit despite the fact that they are dispatched infrequently.

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161 See Collin Cain & Jonathan Lesser, Bates White, A Common Sense Guide to Wholesale Electric Markets 14-15 (2007), https://www.bateswhite.com/media/publication/55_media.741.pdf [https://perma.cc/KU3R-8VLS] (“[G]enerators not only have to cover all of their variable costs, like fuel, but they must earn sufficient revenues to pay their fixed costs . . . . Investors will include all of these costs as an opportunity cost of doing business, and will not enter a market if they believe they will not be able to recover all of their costs . . . . through market prices.”); see also Michael Hogan, Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System, 30 Electricity J. 55, 56 (2017) (“When supply margins are tight, the demand for energy and balancing services can drive marginal costs well above the variable cost of the last kWh sold in the forward market. This in turn reveals the true window of opportunity for consumers to play their role in balancing supply and demand.”).


163 See id.


166 See Peter Cramton, Electricity Market Design, 33 Oxford Rev. Econ. Pol’y 589, 597 (2017) (“In real time, market power becomes a more severe problem as the system operator has fewer options—resources are limited to those online and the ability of the resources to react is limited by ramp rates. Some method of mitigating market power is required.”). For a fascinating and provocative investigation into the role price formation plays in market design, with a particular focus on electricity markets, see William Boyd, Ways of Price Making and the Challenge of Market Governance in U.S. Energy Law, 105 Minn. L. Rev. (forthcoming 2020).
2. Market Manipulation

A central challenge in electricity markets is that a system that relied entirely on energy markets could lead to market manipulation and excessive price volatility. To avoid these problems, every market regulator in the United States sets a ceiling on its energy market’s clearing price.167

In the absence of these administrative constraints, generators may manipulate the market for their own benefit. Imagine if a company owns two baseload generators and several peaking plants. The company might induce shortage conditions by closing one of its baseload generators for repairs. This could cause prices to skyrocket, allowing the company to collect high prices with its remaining baseload generator and its peaking plants. Alternatively, generators that know that their bids will determine the clearing price can simply drive the clearing price up by withholding supply or submitting excessively high bids.168 Peaking plants pose special problems because they will by definition have market power.169 They know that they do not face competition because they are the last units dispatched. As a result, they can raise prices beyond what would be necessary for them to recover their capital costs and make a reasonable profit.170

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167 See, e.g., Robbie Orvis & Mike O’Boyle, It’s Time to Refine How We Talk About Wholesale Markets, GREENTECH MEDIA (Feb. 12, 2018), https://www.greentechmedia.com/articles/read/its-time-to-refine-how-we-talk-about-wholesale-markets [https://perma.cc/44QR-QZVB] (describing an action by FERC to “raise[] the price cap to $2,000 per megawatt-hour in all FERC-regulated markets” other than Texas, which already had a price cap of $9,000 per megawatt-hour). For an insightful article arguing that traditional approaches to market power abuses are ill suited to modern energy markets, see David B. Spence & Robert Prentice, The Transformation of American Energy Markets and the Problem of Market Power, 53 B.C. L. REV. 131, 132-33 (2012).

168 See, e.g., Abuse of Power: How Manipulative Trading Undermined Energy Deregulation, KNOWLEDGE@WHARTON (June 5, 2002), https://knowledge.wharton.upenn.edu/article/abuse-of-power-how-manipulative-trading-undermined-energy-deregulation [https://perma.cc/BWU5-9EMX] [hereinafter Abuse of Power] (“[I]n the electricity industry, . . . generators with as little as a 5% market share can send prices soaring by withholding supplies. Because electricity is a vital necessity with inelastic demand, and because it cannot be stored in substantial quantities, its price is extraordinarily volatile.”).

169 See Stephen J. Rassenti, Vernon L. Smith & Bart J. Wilson, Controlling Market Power and Price Spikes in Electricity Networks: Demand-Side Bidding, 100 PROC. NAT’L ACAD. SCI. 2998, 2999 (2003) (“A firm is conventionally said to have market power when it can set a price greater than the marginal cost and still make positive sales.”).

170 See Rassenti, Smith & Wilson, supra note 169, at 3002 (2003) (“Under the conditions of no demand-side bidding, . . . the distribution of ownership of a given set of generating assets can contribute markedly to the exercise of market power by well positioned generator owners in supply-side auctions in which demand is fully revealed . . .: Only generators can behave strategically, and they do so to the disadvantage of buyers.”). This is one of only many strategies generators can adopt to exercise market power in the absence of offer caps. For a comprehensive description of how firms exercised market power in electricity markets during the California Energy Crisis, see Frank A. Wolak, Lessons from the California Energy Crisis, in ELECTRICITY DEREGULATION, supra note 86, at 145, 154-62.
This type of market manipulation can itself cause reliability problems. In the early 2000s, California relied on energy markets to meet demand.\(^{171}\) Aggressive market manipulation by generators on the margin contributed to dramatic price spikes.\(^{172}\) Large companies devised a number of strategies to induce scarcity and then provide electricity when prices skyrocketed.\(^{173}\) These practices have been documented in the extensive literature on the California energy crisis.\(^{174}\)

A related problem with energy-only markets is that electricity demand is inelastic.\(^{175}\) In most markets, demand decreases when price increases. Electricity markets are different. When consumers want electricity, they want it immediately and, because retail rates are fixed in advance, they know they will receive it at a predetermined price. This means that when demand is high and additional supply is accordingly scarce, the remaining suppliers can submit extremely high bids because there is little risk that consumers will stop using electricity.\(^{176}\)

Moreover, because of the significant amount of time it takes to build new generators, even functional energy markets result in unpredictable swings in supply. After the market signals that new supply is needed, it may take years for new generators to finish construction and begin operating.\(^{177}\) Thus, even when prices encourage generators to enter the market, there may be periods

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\(^{171}\) See Wolak, supra note 170, at 148-50, 152-54 (discussing deregulation generally and the resulting energy market system in California).

\(^{172}\) See id. at 163-64.

\(^{173}\) See id. at 158-59 (summarizing evidence that “the substantially higher prices during the summer of 2000 were the result of the unilateral profit-maximizing actions of suppliers to the California energy markets”).


\(^{175}\) Inelastic demand means that demand for a product does not increase or decrease based on changes in price. People will buy the same amount of the product regardless of whether the price drops or increases. See Inelastic Demand, CORP. FINANCE INST., https://corporatefinanceinstitute.com/resources/knowledge/economics/inelastic-demand [https://perma.cc/RF5S-52K6].

\(^{176}\) See Joskow, supra note 15, at 29 (“Because electricity demand is very inelastic in the short run and electricity cannot be stored, individual suppliers may be able to move prices significantly even in markets that are not very highly concentrated by traditional standards.”).

\(^{177}\) See OMS Resource Adequacy Working Group, Resource Adequacy and Capacity Markets Principles 3 (Mar. 12, 2004), http://www.misostates.org/images/PositionStatements/OMSRAWGPrinciplesasapprovedbyOMSBoard3-12-04.pdf [https://perma.cc/XY3T-UQ3H] (identifying “long lead times for new construction” as one reason that “electric supply shortages could occur”).
of resource inadequacy due to the fact that potential new suppliers cannot respond quickly to market opportunities.\footnote{See id. ("Electric supply can be considered inelastic over the short term because it can be difficult for markets to respond quickly to unexpected shortages. Absent adequate planning reserves, prolonged periods of volatile market prices are likely.").}

3. Offer Caps Deter Market Manipulation

Every regulator in the United States has adopted offer caps to avoid the problems described above.\footnote{Udi Helman, Benjamin F. Hobbs & Richard P. O’Neil, The Design of US Wholesale Energy and Ancillary Service Auction Markets: Theory and Practice, in COMPETITIVE ELECTRICITY MARKETS: DESIGN, IMPLEMENTATION, PERFORMANCE 179, 193-94 (Fereidoon P. Siohansi ed., 2008) (discussing the effects of “supply offer caps,” which were adopted “for purposes of market power mitigation and the lack of demand bids”); see also 2017 IRC MARKETS COMMITTEE EXECUTIVE SUMMARY (2017), https://isorto.org/wp-content/uploads/2018/09/20179905_2017IRCMarketsCommitteeExecutiveSummaryFinal.pdf (describing offer caps in every RTO).} Offer caps remove incentives to manipulate prices and manufacture scarcity by reducing the revenues generators enjoy when supply is scarce.\footnote{See William W. Hogan, Electricity Scarcity Pricing Through Operating Reserves, ECON. ENERGY & ENVTL. POL’Y, Sept. 2013, at 65, 69 (“A problem with increasing offer caps arises in the tradeoff for mitigating market power. A principal purpose of generator offer caps is to mitigate the exercise of market power through economic withholding.”); see also Wolak, supra note 170, at 155 (describing the imposition of offer caps in CAISO’s energy and ancillary service markets in the summer of 1998, in response to skyrocketing bids from suppliers).} In doing so, they reduce a region’s vulnerability to market manipulation. Offer caps also reduce volatility by preventing prices from skyrocketing.

4. Offer Caps Create a Missing Money Problem

Although offer caps discourage market manipulation and reduce volatility, they can prevent electricity prices from rising high enough to support peaking plants and other generators that rely on high inframarginal rents.\footnote{See David Newbery, Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors 3 (Energy Pol’y Research Grp., Working Paper No. 1508, 2015), https://www.epri.group.cam.ac.uk/wp-content/uploads/2015/03/1508_updated-July-2015.pdf [https://perma.cc/zVMY-PYZP] ("If investment decisions could be solely guided by strictly commercial decisions and if markets were not subject to policy interventions or price caps, it is plausible that capacity adequacy could be delivered by profit-motivated generation investment without explicit policy guidance.").} Peaking plants are essential to a well-functioning electric grid because they ensure that there is enough supply to meet demand.\footnote{Flexible Peaking Resource, ENERGY STORAGE ASSN: ESA BLOG (Sept. 24, 2013), https://energystorage.org/flexible-peaking-resource [https://perma.cc/U9zW-8M8V].} However, peaking plants struggle to make a profit or recoup their costs when regulators limit the prices...
they can charge. In the few periods in which peaking plants are dispatched, their high bids always set the market clearing price. When offer caps constrain the price peaking plants and other generators bid, those units often do not make enough of a profit during shortage conditions to cover their fixed costs. Without some other source of revenue, these peaking plants would retire and replacements would not be built.

C. Finding the Missing Money

In the traditional utility model, concerns about reliability were addressed when the public utility commission approved a utility’s proposed rate. The utility would build generators that could provide electricity to meet spikes in demand. As the previous Section showed, in moving to a system in which generators are compensated based on their marginal costs and energy market prices are capped, regulators created a missing money problem.


184 See id. at 2 (“The prevalence of regulatory intervention to suppress energy prices even when they reflect legitimate scarcity rents justifies the concern that indeed generators would not be able to cover their fixed costs through energy sales alone.”).


186 See Shelley Welton, Public Energy, 92 N.Y.U. L. REV. 267, 322-23 (2017) (explaining that under the traditional form of public utility regulation in which price is set by a utility commission, “[t]ypically, commissions also provide some sort of incentive to utilities to maintain a certain level of service reliability, since utilities would otherwise be tempted to skimp on quality of service in order to cut costs and increase profits”); JANINE MIGDEN-OSTRANDER ET AL., REGULATORY ASSISTANCE PROJECT, DECOUPLING CASE STUDIES: REVENUE REGULATION IMPLEMENTATION IN SIX STATES 4 (2014), http://www.puc.state.pa.us/docs/147846.pdf (https://perma.cc/QH69-VATW] (“Utilities have embedded investment-related and labor costs (not sensitive to volume) included in their rates to support investments already made and necessary for good service, reliability, safety, and other utility services, which are adjusted during periodic rate cases.”) (citation omitted); see also DAN CROSS-CALL ET AL., ROCKY MOUNTAIN INST., AMERICA’S POWER PLAN & AEE INST., NAVIGATING UTILITY BUSINESS MODEL REFORM: A PRACTICAL GUIDE TO REGULATORY DESIGN 11 (2018), https://rmi.org/wp-content/uploads/2018/10/RMI_Navigating_ Utility_Business_Model_Reform_2018-1.pdf [https://perma.cc/7WCJ-89UJ] (“The conventional utility business model largely succeeded at delivering on historical responsibilities for affordability, safety, and reliability.”).

187 See Is It Time to Deregulate All Electric Utilities?, WALL ST. J. (Nov. 13, 2016, 10:01 PM), https://www.wsj.com/articles/is-it-time-to-deregulate-all-electric UTILITIES-1479092461 [https://perma.cc/467D-SGJC] (contribution from Andrew N. Kleit) (“Electricity for the most part can’t be stored, meaning supply must nearly match demand at all times or the grid could come under stress and crash . . . . [M]any supply-and-demand challenges could be solved if the cost of storing electricity was brought down to economical levels.”).
This Section describes the steps regulators have taken to deal with the missing money problem. Regulators have responded to the missing money problem either through scarcity pricing or resource adequacy requirements.\textsuperscript{188} Scarcity pricing sets offer caps at high levels to ensure that energy markets provide enough revenue to maintain adequate reserves. Alternatively, regulators can rely on resource adequacy requirements. Such policies compensate generators for being available to provide electricity—not for actually providing it.

1. Scarcity Pricing

One way to procure sufficient reserves is to let prices rise substantially when supply is scarce.\textsuperscript{189} Texas is the only state that relies primarily on scarcity pricing to maintain adequate reserves.\textsuperscript{190} ERCOT, the ISO that manages electricity in Texas, allows prices to reach $9000 per megawatt-hour when supply is low.\textsuperscript{191} There are four challenges with scarcity pricing, many of which parallel the challenges of energy-only markets described in Section II.B.

a. Unpredictability

A market that procures reserves through scarcity pricing allows market participants—rather than FERC or the grid operator—to determine when generators will enter and exit the market. ERCOT may feel that scarcity prices are high enough to encourage efficient entry. However, because ERCOT does not actually procure capacity, it has to assume that (a) prices will procure the right amount of load, and (b) generators will actually respond to price signals.

Even if regulators are able to determine the correct scarcity price, there is delay between when the market signals that new load is necessary and when suppliers actually enter the market. That delay could undermine reliability in

\textsuperscript{188} As this Section explains, resource adequacy requirements include both mandatory capacity markets and markets in which LSEs are required to maintain an administratively set level of reserves.

\textsuperscript{189} See Gavin Bade, \textit{The Great Capacity Market Debate: Which Model Can Best Handle the Energy Transition?}, \textit{Util. Dive} (Apr. 18, 2017), \url{https://www.utilitydive.com/news/the-great-capacity-market-debate-which-model-can-best-handle-the-energy-transition/440657} [https://perma.cc/AX98-DX9B] (“In Texas, regulators ensure reliability through ... scarcity pricing, which allows real-time electricity prices to reach as high as $9000/MWh ... Instead of guaranteeing generation revenue through a capacity market, the promise of high prices is supposed to incentivize generators to build new plants and keep them ready to operate.”).

\textsuperscript{190} See id. (“Of the wholesale electricity markets that serve two-thirds of the U.S. population, only two—[ERCOT] and [SPP]—do not have capacity markets.”).

\textsuperscript{191} ERCOT, \textit{About the Operating Reserve Demand Curve and Wholesale Electric Prices} (May 2014), \url{https://hepg.hks.harvard.edu/files/hepg/files/ordcupdate-final.pdf} [https://perma.cc/Wy8A-LVVY] (explaining that under ERCOT’s Operating Reserve Demand Curve, “wholesale prices in the real-time energy market will increase automatically as available operating reserves decrease,” up to the price of $9000 per megawatt-hour when reserves drop below 2000 megawatts).
the short run. If suppliers fail to respond quickly to price signals, even properly priced markets will fail to procure sufficient supply. Regulatory risk-aversion may thus induce regulators to give generators other sources of revenue in order to maintain a stable level of supply.

A related challenge is that revenue uncertainty increases price volatility. Because regulators cannot predict weather patterns far in advance, they cannot determine how much money generators will make in a given time period.

b. Market Manipulation

Another challenge with scarcity pricing is that it remains vulnerable to the abusive practices that vexed California in 2000 and 2001. Although offer caps limit the extent to which prices can increase, a system that relies exclusively on scarcity pricing still has to provide a substantial windfall to generators that sell electricity when supply is limited. In fact, ERCOT has seen extreme volatility in the amount of supply offered in June and July. These price swings have increased the amount of revenue that goes to generators that operate when supply is scarce, leading some to theorize that large companies are manipulating the market to manufacture scarcity conditions. See id.

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193 As David Patton, market monitor for PJM and other RTOs, explained during a panel at the Energy Bar Association’s 2016 Annual Meeting:

Shortage pricing is not like a capacity market where you’re going to get a level of revenue that might fluctuate by 10 to 20% a year. With shortage pricing, you might get 10 years of revenue in one year and then the other nine years the generators are going to think they’re going bankrupt . . . [because shortage prices] increase exponentially when you get unusually hot weather and unusually high loads or unusually poor generator performance.”


195 See id. (speculating that ERCOT’s percent price swings in June 2012 were the result of market manipulation and observing that “ERCOT has been manipulated before”); see also L.M. Sixel, A May Price Spike Shows Vulnerability to Market Manipulation—and Cost to Consumers, HOUSTON CHRON. (Aug. 2, 2019, 2:37 PM), https://www.houstonchronicle.com/business/energy/article/A-
Moreover, in 2019, ERCOT’s reserves declined below nine percent despite the fact that the state aims to maintain approximately fourteen percent reserve capacity. This has led to speculation that Texas is vulnerable to market manipulation as companies that own both peaking and non-peaking plants will be able to create scarcity pricing conditions by withholding supply strategically in order to cause energy prices to increase.

c. Political Will

The third and perhaps most important problem with scarcity pricing is that regulators do not seem to have the political will to commit to an electricity market in which price signals—rather than administrative reserve requirements—secure resource adequacy. Even if scarcity pricing could maintain adequate supply, and persuasive economic arguments indicate that it can, the fact that regulators are concerned about the problems enumerated above suggests that policymakers need to think about alternative ways to procure reserves. No state other than Texas relies on energy markets to procure supply. Other grid operators have determined that energy-only markets allow unacceptable levels of volatility and fail to maintain sufficient reserves.

At the very least, the fact that most of the United States refuses to commit to scarcity pricing illustrates the need to think carefully about how to support other markets that can procure sufficient supply while preserving competition

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196 See News Release: ERCOT’s Reserve Margin Climbs 2% for Summer 2020, ERCOT (Dec. 5, 2019), http://www.ercot.com/news/releases/show/195386 [https://perma.cc/2ZBT-RVNM] (“Power companies have exploited weaknesses in the design of Texas’ deregulated market almost from the day it began operating in 2002 and often done so with few consequences, reaping windfalls that have cost consumers, traders, industrial customers and retail power companies hundreds of millions of dollars.”).

197 See, e.g., Sixel, supra note 195 (“Lawmakers and regulators . . . have done little to harden the system against manipulation and, in some ways, provided incentives for companies to game the market. When it finds irregularities that push prices artificially high, ERCOT rarely reprices transactions and orders power companies to give up the gains.”).

198 See Hogan, supra note 150, at 6-23 (explaining how energy-only markets could provide resource adequacy and summarizing the economic literature).

199 See Bade, supra note 189 (“Of the wholesale electricity markets . . . , only two—[ERCOT] and [SPP]—do not have capacity markets.”).

200 For example, when PJM first developed its capacity market, it did so because its “existing market rules . . . fail[ed] to set prices adequate to ensure sufficient resources” and “create[d] significant price volatility for electric supply.” PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, slip op. at 2-3 (Dec. 22, 2006).
and accommodating state renewable energy policies. A recent exchange between Harvard economist William Hogan and PJM executives illustrates this dynamic. After Hogan said that “[l]ife is too short to spend your time trying to perfect capacity markets,” PJM Market Monitor Joe Bowring responded, “it’s easy enough to say in a theoretical world that scarcity pricing should take care of everything. But we have yet to see that demonstrated in the real world.” 201 While it is certainly possible that ERCOT will continue to rely on scarcity pricing, the unpredictability, threat of market manipulation, and widespread antipathy to energy-only markets means that it is important to consider alternative market designs.

2. Resource Adequacy Requirements

Resource adequacy requirements are a more common solution to the missing money problem. In addition to or instead of compensating generators for providing electricity, resource adequacy requirements compensate generators for being available to provide electricity. 202 Given that every state besides Texas maintains reliability through a resource adequacy requirement, we expect capacity payments to increase in importance as energy market prices continue to decline.

a. Reserve Obligations

One type of resource adequacy requirement, which we endorse in Part VI and which is used to some extent in the Midwest and California, assigns reserve obligations to LSEs, which procure capacity for themselves but must meet administratively established reserve margins. 203 The other option,

201 Heidorn, supra note 193 (internal quotation marks omitted).

202 See Bushnell et al., supra note 24, at 3 ("Outside of ERCOT, supply resources in other U.S. markets operated by [RTOs] can earn revenues for the provision of capacity, a product defined by the expected potential to supply energy.").

203 See Planning Resource Auction, MISO, https://www.misoenergy.org/planning/resource-adequacy/ [https://www.misoenergy.org/planning/resource-adequacy/?t=10&dp=088s&FileName&sd=desc] (last visited Feb. 11, 2020) (“In the MISO region, customer-facing utilities are responsible for making sure they can meet customer needs.”). California’s system is similar to that of MISO. In California, the California Public Utility Commission (CPUC) imposes “resource adequacy” requirements on LSEs. See Resource Adequacy, CAL. PUB. UTIL. COMMISSION, http://www.cpuc.ca.gov/RA [https://perma.cc/6642-RQSE] (last visited Feb. 11, 2020) (noting that the CPUC imposes resource adequacy obligations on all LSEs in the CPUC’s jurisdiction). MISO runs a centralized capacity auction, known as the planning resource auction, but also allows LSEs to meet the resource adequacy requirement by submitting a fixed resource adequacy plan or through bilateral contracting. MISO, 2019/2020 PLANNING RESOURCE AUCTION (PRA) RESULTS 3 (2019), https://cdn.misoenergy.org/20190412_PRA_Results_Posting36165.pdf [https://perma.cc/YZ5Q-65RQ] [hereinafter 2019/2020 PRA RESULTS]. Unlike MISO, the CPUC does not run a centralized market. See id. However, the California grid operator, CAISO, is beginning to add elements of a capacity market through the Capacity Procurement Mechanism that would allow the ISO—rather than the LSEs—to procure
which is used in the East Coast markets, is a central capacity market, in which the RTO runs periodic auctions to acquire capacity on behalf of the LSEs. The RTO then allocates costs to the LSEs.\footnote{See Capacity Procurement Mechanism Replacement, CAISO, http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/CapacityProcurementMechanismReplacement.aspx [https://perma.cc/HQ4J-666P] (last visited Feb. 11, 2020) (describing a proposal that includes "a durable mechanism and market-based price for the ISO to procure capacity not designated for resource adequacy in order to meet reliability needs"). The Southwest Power Pool (SPP), which serves the Great Plains states, also has a resource adequacy requirement but no centrally administered market. See Resource Adequacy, SPP, https://www.spp.org/engineering/resource-adequacy [https://perma.cc/LWF4-V38X] (last visited Feb. 11, 2020) (stating that SPP achieves resource adequacy through the implementation of demand and supply adequacy requirements).}

Under resource adequacy requirements without mandated capacity auctions, LSEs can self-supply, contract bilaterally, or purchase reserves through a central auction.\footnote{See, e.g., CAPACITY MARKET OPERATIONS, PJM, PJM MANUAL 18: PJM CAPACITY MARKET 16 (4th rev., effective Dec. 5, 2019), https://pjm.com/-/media/documents/manuals/mr8.ashx?la=en [https://perma.cc/6MYY-RXEU] [hereinafter PJM MANUAL 18: PJM CAPACITY MARKET] ("Under RPM, each LSE that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone."). See 2019/2020 PRA RESULTS, supra note 203, at 3.} LSEs that prefer to self-supply or purchase load by negotiating with independent power producers are free to do so.\footnote{See Midcontinent Indep. Sys. Operator, Inc., 162 FERC ¶ 61,176, slip op. at 1-2 (Feb. 18, 2018) (stating the LSEs in MISO can satisfy their resource adequacy obligations in any of four ways: "(1) purchase capacity through the Planning Resource Auction (Auction); (2) submit a Fixed Resource Adequacy Plan to demonstrate that it has designated capacity to meet all or a portion of its Reserve Requirement, (3) self-schedule capacity and bid it into the Auction at a price of zero, and/or (4) pay the Capacity Deficiency Charge"); MISO, FERC Electric Tariff, Module E-1, § 69A (35.0.o), https://cdn.misoenergy.org/Module%20E-1108026.pdf ("LSEs will meet their [planning reserve margin requirement] by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling [Zonal Resource Credits (ZRCs)]; (iii) purchasing ZRCs through the Planning Resource Auction process; and/or (iv) paying the Capacity Deficiency Charge.").} If a state requires that an LSE procure in-state natural gas or rely more heavily on zero-carbon sources, the LSE can find supply that both satisfies the federal reserve mandate and meets its state’s needs.

b. Capacity Markets

The East Coast capacity markets are more intrusive than simple resource adequacy requirements.\footnote{These centralized capacity markets are not strictly mandatory and do not prevent utilities from procuring capacity through bilateral contracts. What distinguishes the East Coast capacity markets is that a regulator or grid operator requires LSEs to participate in a centrally administered capacity auction in which the regulator or grid operator determines the winning bids. See PJM MANUAL 18: PJM CAPACITY MARKET, supra note 204, at 16 (explaining that “[p]articipation by [LSEs] in the [Reliability Pricing Model] for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement . . . Alternative制订).} In these markets, existing generators and proposed

capacity when needed. See Capacity Procurement Mechanism Replacement, CAISO, http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/CapacityProcurementMechanismReplacement.aspx [https://perma.cc/HQ4J-666P] (last visited Feb. 11, 2020) (describing a proposal that includes "a durable mechanism and market-based price for the ISO to procure capacity not designated for resource adequacy in order to meet reliability needs"). The Southwest Power Pool (SPP), which serves the Great Plains states, also has a resource adequacy requirement but no centrally administered market. See Resource Adequacy, SPP, https://www.spp.org/engineering/resource-adequacy [https://perma.cc/LWF4-V38X] (last visited Feb. 11, 2020) (stating that SPP achieves resource adequacy through the implementation of demand and supply adequacy requirements).}
new generators submit bids (in dollars per megawatt-day) in which they offer to be available to supply power (in megawatts) for a commitment period in the future.\textsuperscript{208} Grid operators set up a merit order and clear enough power to cover the administratively determined demand curve.\textsuperscript{209} The marginal generator sets the market-clearing price for capacity. To meet its capacity obligation, a generator must bid into the energy market for the future commitment period even if that generator does not clear.\textsuperscript{210} LSEs are

\begin{itemize}
\item \textit{id.} at 84-88 (discussing the circumstances in which buyers and sellers can enter into bilateral contracts for the sale and purchase of capacity); \textit{id.} at 200-02 (explaining how LSEs can opt out of the Reliability Pricing Model through the Fixed Resource Requirement, which allows LSEs to self-supply capacity if they provide, among other things, at least four months notice and demonstrate that they have sufficient resources to meet the reserve requirement for five consecutive years).
\item See Bushnell et al., \textit{supra} note 24, at 28 (“Resources with capacity that clears in a capacity market or is committed to meet an RA requirement have obligations to be available and perform in Day-Ahead and Real-Time energy markets.”).

Table 2: Representative Capacity Market Pricing

<table>
<thead>
<tr>
<th>ISO / RTO</th>
<th>Name</th>
<th>Forward Commitment Period</th>
<th>Price Range over Last Ten Auctions</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM</td>
<td>Reliability Pricing Model</td>
<td>3 years ahead, 1 year&lt;sup&gt;215&lt;/sup&gt;</td>
<td>$16 to $165 / MW-day&lt;sup&gt;216&lt;/sup&gt;</td>
</tr>
<tr>
<td>NYISO</td>
<td>Installed Capacity Market</td>
<td>1 month ahead, 6 months&lt;sup&gt;217&lt;/sup&gt;</td>
<td>$0 to $604 / MW-day&lt;sup&gt;218&lt;/sup&gt;</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>Planning Resource Auction</td>
<td>3 years ahead, 1 year&lt;sup&gt;219&lt;/sup&gt;</td>
<td>$66 to $583 / MW-day&lt;sup&gt;220&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

In regions that rely on mandatory capacity markets, the trend has been for these markets to make up an increasing share of generator revenue. PJM’s capacity market, for example, now provides four times more revenue than it did when it was developed in 2007 and twenty percent of total revenue for generators operating in the Mid-Atlantic.<sup>221</sup> In ISO-NE, PJM, and NYISO, the three markets with mandatory capacity markets, between roughly twenty

<sup>215</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>216</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>217</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>218</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>219</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>220</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.<sup>221</sup> See id. (strip auction results from Winter 2015–16 to Summer 2020, accounting for lows and highs in each auction). Note that $1/kW-month * (12 months / 365 days) * (1000 kW / 1 MW) = $32.9 / MW-day.
percent (NYISO, PJM) and forty percent (ISO-NE) of wholesale electricity costs was due to capacity market payments.222

III. RENEWABLES EXACERBATE THE MISSING MONEY PROBLEM

The previous Part showed that offer caps have contributed to a missing money problem that has prompted regulators to find other sources of revenue to support resource adequacy. This Part explains why growing volumes of renewables increase the need for regulatory interventions to support resource adequacy.

It is worth making clear at the outset that it is theoretically possible for energy-only markets to provide resource adequacy even with high levels of renewables. If regulators were comfortable with extreme price swings and power producers could make investment decisions with perfect foresight, energy market prices could conceivably rise high enough to provide sufficient compensation for peaking plants and other generators that support grid reliability.223 The purpose of this Part is therefore not to show that there is no scenario in which energy markets could accommodate higher levels of renewables. It is rather to show that by suppressing energy market prices, renewables exacerbate the features of the grid that have already led regulators to intervene in electricity markets.

Perhaps more importantly, regulators and grid operators believe that the missing money problem will increase as renewable penetration grows, and they are already taking intervening steps to provide other sources of revenue for generators perceived to be necessary to reliability. According to ISO-NE, “[a]dditional renewables are expected to decrease wholesale electric energy prices, which will result in increased capacity prices to ensure resource adequacy.”224 Other grid operators have echoed this view.225 Thus, despite the ability of theoretical economists to model a system in which energy-only markets procure resource adequacy in a high-renewable world, academics and policymakers need to consider alternative approaches that preserve competitive dynamics while integrating clean energy resources.

A. Declining Clearing Prices Are Transforming Electricity Markets

The combination of increasingly competitive renewables, state clean energy policies, and inexpensive natural gas has already transformed the

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223 See Hogan, supra note 150, at 1-3 (showing that if offer caps were removed and demand was responsive to supply, then the market might provide sufficient revenue during scarcity conditions to support necessary supply).
224 See ISO New England, supra note 34, at 1.
225 See infra Section IV.C.
United States’ resource mix and reduced the contribution of energy markets to generator revenue.\textsuperscript{226} As natural gas and renewables have become less expensive,\textsuperscript{227} they have begun to make up a larger percentage of the power grid.\textsuperscript{228} Lower natural gas prices translate to lower marginal costs for natural gas power plants. This reduces the market-clearing price as the marginal generator is usually a natural gas power plant.

Renewable generators have marginal costs close to zero, such that the entry of these resources shifts the supply curve to the right. This shift causes prices to decline because a lower marginal cost generator sets the clearing price.\textsuperscript{229} Figure 3 demonstrates these two effects.

Figure 3: Price Depression Effects of Cheap Natural Gas and Renewables\textsuperscript{230}


\textsuperscript{227} See LAZARD, supra note 226, at 7; Coley Girouard, The Numbers Are in and Renewables Are Winning on Price Alone, ADVANCED ENERGY PERSP. (Dec. 5, 2018, 4:00 PM), https://blog.aee.net/the-numbers-are-in-and-renewables-are-winning-on-price-alone [https://perma.cc/74lx-4SUT].


\textsuperscript{229} See SEEL ET AL., supra note 33, at 3-4 figs. 1-2 (showing this effect with graphs).

\textsuperscript{230} Data for Figure 3 came from LAZARD, supra note 146; U.S. ENERGY INFO. ADMIN., supra note 146.
As Figure 4 shows, increased use of natural gas and renewables has already caused energy market prices to decline significantly. Energy market prices peaked in 2008 and fell more than fifty percent in the ensuing decade. In 2006, energy prices averaged approximately $80 per megawatt-hour. Prices increased to $160 per megawatt-hour in 2008 and have steadily declined to about $35 per megawatt-hour.

Lower energy market prices have begun to challenge the ability of some generators, especially coal and nuclear power plants, to cover their fixed costs. Since 2010, declining prices have forced roughly a third (by capacity)

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231 The data for Figure 4 came from the U.S. Energy Information Administration’s Historical Wholesale Market Data for the years 2006–2017. See Wholesale Electricity and Natural Gas Market Data, U.S. ENERGY INFO. ADMIN. (Feb. 27, 2020), https://www.eia.gov/electricity/wholesale [https://perma.cc/37LE-NQCM]. Specifically, energy market prices have fallen 66 percent in CAISO, 64 percent in ISO-NE, 62 percent in PJM, and 52 percent in MISO. See id. Figures reported are monthly averages weighted by sales volume and adjusted for inflation. In the years leading up to 2008, energy prices crept up from around $60 per megawatt-hour to above $100 per megawatt-hour. With the discovery of abundant shale gas in 2008, prices fell to around $30 per megawatt-hour. See id. There have been occasional price spikes since then, most notably in response to the 2014 polar vortex, but prices have generally remained in the $30–$50 per megawatt-hour range. See id.

232 Wholesale Electricity and Natural Gas Market Data, supra note 231; see also supra note 231.

233 Coal and nuclear power plants in regulated regions, such as the Northwest and Southeast, are also affected, though the price signal is muted by utility and commission decisionmaking. As generation in these regions remains subject to utility rate regulation, the retirement decision for these power plants is subject to public utility commission ratemaking rather than market forces. For more detail on the geographically differentiated history of restructuring, see supra Part II.
of the then-active coal power plant fleet to retire.\textsuperscript{234} To date, the major driver of these lower energy market prices and resulting plant closures has been inexpensive natural gas. According to a Lawrence Berkeley National Lab report:

\[\text{[T]he primary driver of the decline in average wholesale electricity prices between 2008 and 2016 in ERCOT and CAISO is the decline in natural gas prices. We find that growth in [variable renewable energy] generation contributed less than 5% to the overall price decline, whereas natural gas price reductions contributed 85-90% of the overall decline in wholesale electricity prices in these markets.}\textsuperscript{235}

As detailed below, the growing penetration of renewables is expected to reinforce and continue this price suppression trend.

Price suppression has also begun to reduce the role of energy markets in much of the United States. According to FERC and the grid operators, increased volumes of renewables and declining gas prices have increased the importance of capacity markets in many parts of the United States.\textsuperscript{236} In ISO-NE, for example, capacity markets were responsible for slightly more than 10.5% of wholesale electricity costs in 2008 but had ballooned to over thirty-five percent of wholesale electricity costs in 2018.\textsuperscript{237} ISO-NE explained that “[t]he region should expect to see the annual energy-market value continue to decline over time as renewable resources drive down energy-market prices.”\textsuperscript{238} The grid operator believes that capacity markets will provide the


\textsuperscript{235} Wiser et al., supra note 30, at 23.

\textsuperscript{236} See infra Section III.C; infra Table 3.


\textsuperscript{238} Key Grids and Market Stats: Markets, supra note 237.
revenue shortfall. As long as FERC and grid operators feel that these units are necessary for reliability, they will continue to allow the capacity clearing price to rise. Figure 5 illustrates the increasing percentage electricity market payments that are due to capacity markets.

![Figure 5: Percentage of Revenue from Capacity, Energy, and Ancillary Services Markets (ISO-NE)](image)

Declining energy market prices have also forced some plants that used to receive most revenues from energy markets to become newly reliant on capacity market payments. In PJM, for example, seventy-nine percent of nuclear power plants recovered their costs from energy and ancillary services markets in 2013 and one hundred percent recovered their costs from those markets.

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239 See id. ("[A]s energy-market revenues decrease over time, the prices in the capacity and ancillary markets will likely rise to cover the costs for resources that rely solely on market revenue . . . and are needed to balance renewable resources and provide energy security, particularly in winter.").

240 Id.

241 To calculate these numbers, we took that data from ISO-NE’s internal market monitor’s yearly reports. We divided revenues from each market (capacity, energy, and ancillary services) by the sum of the revenues that came from those markets (capacity + energy + ancillary services). The market monitor reports also include regional network load costs. We excluded those payments because they cover transmission facilities and administrative costs and thus are not payments to generators. We also excluded net commitment period compensation revenues (NCPC). NCPC do not fit neatly into any of the markets because they are payments to units that follow the instructions of the grid operator, often as a result of transmission security concerns. NCPC payments were very low throughout the period. Over the past decade, a larger and larger percentage of ISO-NE revenue has come from capacity markets. According to ISO-NE’s internal market monitor, capacity markets accounted for less than eleven percent of generator revenue in 2014 and now account for nearly forty percent of generator revenue.
markets in 2014. By 2017, only twenty-one percent of nuclear plants recovered their costs from energy and ancillary services markets. The result was to increase the importance of capacity payments for nuclear power plants.

B. Long-Term Prospects for Energy Markets

Energy prices will continue to decline as renewable penetration increases. A number of states have developed ambitious clean energy targets that call for renewables to take on a larger share of total power generation. California, for example, recently adopted a bill that calls for fifty percent of the state’s electricity to be powered from zero-carbon sources by 2025, sixty percent by 2030, and one hundred percent by 2045. New York has set a goal of producing only carbon-free electricity by 2040. Many of these states have renewable portfolio standard (RPS) mandates. Moreover, many states in the Midwest have deployed substantial renewable capacity without RPS mandates or other forms of state support. Because these states do not subsidize renewables, the only explanation for this trend is that renewable energy sources have become cost-competitive.

A number of studies have analyzed the causes of declining energy prices. A recent report published by the Lawrence Berkeley National Laboratory

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243 Id.

244 See Spencer Fields, 100 Percent Renewable Targets, ENERGYSAGE (May 2, 2019), https://news.energysage.com/states-with-100-renewable-targets [https://perma.cc/9GHX-EYB7] (identifying which states have 100 percent clean or renewable energy targets, either passed as statutes or announced in executive orders, organized by source of authority and their target compliance dates).


found that achieving a renewable penetration level of forty percent—a relatively modest level of renewable penetration compared to a number of states’ energy goals—would likely increase the number of hours with very low energy prices by nearly twenty percent in some markets.\(^\text{248}\) This level of renewables could lead to the retirement of fourteen percent of Texas’s “firm capacity,” which is capacity that is guaranteed to deliver electricity even under adverse conditions.\(^\text{249}\) The report found that NYISO would experience a thirty-seven and thirty-nine percent decline in average energy prices under a forty-percent-renewables, or “high VRE,” scenario.\(^\text{250}\)

Another group of energy economists reached a similar result about the effects of renewables on price suppression and volatility.\(^\text{251}\) A study conducted by the National Renewable Energy Lab (NREL) stated that “regions with enough generating units with low or zero marginal costs at a given time will tend toward locational marginal prices of approximately zero.”\(^\text{252}\) Based on this finding, NREL concluded that “[t]he prevalence of near-zero locational marginal prices implies that markets for multiple services in addition to the

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\(^{248}\) See SEEL ET AL., supra note 33, at 1-2, 35 (finding that low-marginal-price hours would increase by up to nineteen percent in ERCOT, in a modeled scenario with more than forty percent renewable penetration).

\(^{249}\) See id. at 17 (reaching this result under the assumptions of a modeled high-wind scenario); see also Energy Terms: Firm Power, ENERGY ME, http://www.energy.me/energy-terms/firm-power (last visited May 15, 2020) (defining firm capacity or “firm power”).

\(^{250}\) SEEL ET AL., supra note 33, at 21-22.

\(^{251}\) It is worth noting that the missing money problem is not the only reason renewables will exacerbate price volatility. The fact that renewables are intermittent resources—they operate only when the sun is shining and the wind is blowing—means that periods of abundant supply will lead to scarcity when the sun stops shining and the wind stops blowing. The need to compensate generators that can quickly increase supply during periods of scarcity exacerbates price volatility.

Michael Milligan et al., Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Revenue Sufficiency and Long-Term Reliability, 29 ELECTRICITY J. 26, 32-33 (2016). Numerous economic studies support these conclusions. See AARON BLOOM ET AL., NAT’L RENEWABLE ENERGY LAB., TECHNICAL REPORT NREL/TP-6A20-64472, EASTERN RENEWABLE GENERATION INTEGRATION STUDY 155 (2016), https://www.nrel.gov/docs/fy16osti/64472.pdf [https://perma.cc/7QQF-NJ52] (“In futures with high amounts of wind and [photovoltaic energy], system and plant operators will need to focus their attention on different times of day and could expect to cycle or ramp their resources more frequently. If . . . structures are not in place to incentivize this flexibility, resources may exit the market . . . .”); DAVID J. MAGGIO, IMPACTS OF WIND-POWERED GENERATION RESOURCE INTEGRATION ON PRICES IN THE ERCOT NODAL MARKET 2-3 (2012) (presented at the 2012 Institute of Electrical and Electronics Engineers Power and Energy Society General Meeting), https://ieeexplore.ieee.org/document/634461 [https://perma.cc/KWP8-FXZA] (calculating the added cost of greater reliance on ERCOT’s ancillary services as the proportion of wind-powered generation resources in ERCOT’s total system energy increases and forecast error increases as a result); Milligan et al., supra, at 32 (“New electricity market entrants with very low variable costs create revenue sufficiency challenges for marginal units.”).

energy market would likely be needed to reduce revenue risk and to provide financial incentive to generators for producing renewable energy and ensuring reliability. 253 Given that most states have already intervened to limit volatility and reduce price spikes, and that grid operators have expressly stated that they expect renewables to increase the need for capacity markets, it stands to reason that many states will become increasingly reliant on capacity payments and potentially outright bailouts.

These analyses may not predict with pinpoint accuracy how extensively energy prices will decline as renewables make up an increasing share of total electricity production. Because we expect regulators to intervene to ensure resource adequacy, we do not expect prices to follow these patterns precisely. 254 The point is simply that price suppression driven by renewables has a dramatic effect on energy market revenues. A world with high levels of renewables translates into lower wholesale energy prices, which reduces revenues available to all generators. If regulators continue to rely on a payment system based around energy market prices with relatively low offer caps, generator revenues will become more volatile and operating profits for many generators will continue to decline. This threatens the investment incentives of all resources and creates pressure for regulators to turn to other sources of revenue. Unless offer caps increase significantly, which regulators seem reluctant to allow, then FERC and grid operators will rely more heavily on capacity payments and subsidies that support critical generators.

FERC and economists sometimes liken energy markets to some sort of idealized competitive process that exists free from regulatory interference, 255 but it should by now be apparent that any “threat” posed by renewables is a regulatory failure—not an economic failure. FERC and grid operators have developed a payment system in which unit commitment and economic dispatch depend on the marginal costs of the marginal bidder, and they have implemented offer caps that make it difficult for generators to recover costs when supply is scarce. The economic challenges posed by high volumes of renewables thus result from the series of regulatory and legislative interventions that have occurred since FERC deregulated energy markets.

253 Id.

254 As discussed in the next Part, regulators are stepping in prospectively to prevent price suppression and support units needed for grid reliability.

255 See, e.g., Calpine Corp., 169 FERC ¶ 61,239, slip op. at 2 (Dec. 19, 2019) (claiming that certain subsidies “threaten the competitiveness of the capacity market administered by PJM Interconnection”); PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, slip op. at 32 (Dec. 22, 2006) (“In a competitive market, all suppliers will be paid the same price.”).
C. Regulatory Views of the Missing Money Problem

Perhaps the most important reason to consider alternative payment systems is that the regulators charged with overseeing electricity markets believe that renewables suppress energy market prices and increase volatility. For example, David Patton, whose firm Potomac Economics acts as the Internal Market Monitor\(^{256}\) for MISO, ISO-NE, NYISO, and ERCOT,\(^{257}\) has described the importance of capacity payments in a high-renewables electric power grid: “Unless you’re willing to price shortages at $200,000/MWh, you’re not going to meet your planning requirements with the energy market alone.”\(^{258}\) Numerous grid operators have acknowledged that increasing volumes of renewables will render energy markets a less important source of generator revenue. Table 3 compiles quotes to this effect.

<table>
<thead>
<tr>
<th>ISO / RTO</th>
<th>Concern About Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM</td>
<td>“The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and when units do not clear, in the retirement of units. Federal and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.”(^{259})</td>
</tr>
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\(^{258}\) Heidorn, supra note 193.

\(^{259}\) MONITORING ANALYTICS, LLC, Q2 2016 STATE OF THE MARKET REPORT FOR PJM: JANUARY THROUGH JUNE 2016 (2016), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016Q2-som-pjm.pdf [https://perma.cc/DFF4-NHMF]; see also PJM INTERCONNECTION, PJM’S EVOLVING RESOURCE MIX AND SYSTEM RELIABILITY 15 (2017), https://www.pjm.com/~media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.pdf [https://perma.cc/44K5-P772] (“Should the actual, future fuel mix evolve such that the potential exists for the quantity of generator reliability attributes to fall below that which is necessary to maintain reliable grid operations, then operations, market incentives and regulatory structures may need to shift to provide incentives to ensure adequate levels of these attributes are maintained.”).


| ISO-NE | “Additional renewables are expected to decrease wholesale electric energy prices, which will result in increased capacity prices to ensure resource adequacy.”260  
| | “The region should expect to see capacity prices increase over time as renewable resources reduce energy prices, making developers of new resources and owners of existing resources more reliant on capacity market revenues.”261  
| | “[I]nitiatives by the New England states to develop more renewables and clean-energy resources are posing challenges to competitive pricing in the markets, which could ultimately weaken resource adequacy—that is, the assurance that the region has enough resources to meet demand. Further, the markets don’t always show the true costs of inadequate fuel security.”262  
| NYISO | “The centralized grid exists as a dependable mainstay, yet faces unprecedented growth and evolution as large-scale renewables and distributed energy resources connect and place new demands on grid functionality.”263 |

264 Moody’s: Fall in Natural Gas Prices May Lead to Large-Scale Plant Retirement, SNL ENERGY (Apr. 8, 2016)); N.Y. INDEP. SYS. OPERATOR, INTEGRATING PUBLIC POLICY: A WHOLESALE MARKET ASSESSMENT OF THE IMPACT OF 50% RENEWABLE GENERATION 10 (2017), https://www.nyiso.com/documents/2014/1404721/2017%20Market%20Assessment%20with%20percent20Renewables%20Report.pdf/*9180266a-1f62-6049-f4f0-105322a2b692 [https://perma.cc/JRZ5-83R7] (finding that “a significant entry of renewable resources will cause the NYISO to increase the megawatts of Installed Capacity required to meet its resource adequacy criteria.”) |
MISO  “Renewables like wind and solar have low incremental operating costs but variable output subject to the real-time availability of wind and sun. Zero fuel cost and incentives from state and federal entities incent these resources to generate as much as possible at low and sometimes even negative prices. These low costs can impact the energy market revenues paid to all resources by reducing LMPs. Operationally, other resources ramp to adjust to changes to variable renewable energy production to meet net load.”  

CAISO  “[H]igh levels of hydroelectric and renewable generation add lower cost supply, depressing monthly and hourly average wholesale electricity prices due to their relatively low cost. Conversely, low levels of hydroelectric and renewable generation raise costs as higher-cost natural gas generation is necessary to meet demand.”

SPP  “As more renewables are added to the system, there have been an increasing incidence of negative prices . . . and higher real-time price volatility . . . . Lower on-line capacity levels may be a consequence as market participants and market operators adjust to these changes in market conditions.”

“In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their scheduled generation.”

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267 Id. at 103.
What is notable about these statements is not that they show that energy markets will fail to adequately compensate renewables. It is that the entities that monitor and regulate electricity markets believe that intermittent renewables exacerbate the missing money problem and have determined that capacity payments and other administrative interventions are the appropriate solutions.

While this Article is critical of the specific strategies grid operators have used to maintain resource adequacy, regulators are correct that renewables will suppress energy market prices and increase price volatility. To trust energy markets to support resource adequacy in a high-renewables world, regulators would have to raise offer caps significantly.\(^\text{268}\) This would further increase volatility and heighten the incentives and consequences of market manipulation.

IV. RATE REGULATION REDUX

The previous Part showed that price suppression driven by renewables will exacerbate the missing money problem, increase price volatility, and suppress energy market prices. This Part shows that regulatory responses to the missing money problem are recreating the inefficiencies that plagued utility rate regulation. Specifically, this Part analyzes capacity market rules, Minimum Offer Price Rules (MOPRs), and reliability-must-run (RMR) contracts. Like cost-of-service regulation,\(^\text{269}\) capacity markets and MOPRs lead to excess capacity and increase prices beyond what is necessary to maintain reliable service. RMR contracts go a step further and reimpose cost-of-service regulation in parts of the grid that claim to have restructured. All of these regulatory interventions favor fossil fuel generators and counteract state clean energy policies.

A. Mandatory Capacity Markets

While mandatory capacity markets might appear to be a sensible response to the missing money problem, in reality they favor incumbents, lead to overcapacity, and raise electricity prices for consumers. PJM, for example, set a reserve target of 16.1 percent for summer 2018, but operated with a 32.8 percent reserve margin.\(^\text{270}\) That is more than twice as much capacity as the

\(^{268}\) See Jenny Riesz, Joel Gilmore & Iain MacGill, Assessing the Viability of Energy-Only Markets with 100% Renewables: An Australian National Electricity Market Case Study, ECON. ENERGY & ENVTL. POL’Y, Mar. 2016, at 105, 121 tbl.1, 122 (estimating that the market offer cap in the Australian National Electricity Market would have to increase to $60,000-$0,000 per megawatt-hour to provide sufficient aggregate revenues to cover costs in a system relying on 100% renewable energy sources).

\(^{269}\) See supra Section I.A.

grid operator claims is needed for reliability. PJM has in this way ensured that generators with 11,000 megawatts of unnecessary capacity will remain in the market for at least three additional years. As one advocate explained, "[t]hat is roughly equivalent to an extra twenty-two coal or gas power plants (at 500 megawatts each) or eleven extra nuclear power plants (at 1,000 megawatts each). ISO-New England’s capacity markets are similarly bloated. Altogether, redundant capacity is costing consumers in ISO-NE, NYISO, and PJM over a billion dollars a year.

Regulators could reduce some of the issues plaguing capacity markets by improving market design. Other challenges, however, are foundational. That is why capacity markets are a second-best option that should be rejected in favor of scarcity pricing or less intrusive resource adequacy requirements. This Section first critiques specific capacity market rules. It then discusses the fundamental features of capacity markets that would render them problematic even if FERC eliminated the rules that discriminate against renewables.

1. Discriminatory Capacity Market Rules

A core problem with capacity markets is that regulators—rather than market participants—determine the value attached to resources. Grid operators identify resources that provide essential services and introduce regulatory barriers that prevent other resources from increasing their own revenues, even when they are able to provide the services needed to support reliability. In doing so, regulators shield incumbents from competitive forces.

TM6W]. That number is expected to balloon to forty-five percent by 2021. See id.; see also PJM, 2020/2021 RPM BASE RESIDUAL AUCTION RESULTS 1 (2018), http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.aspx [https://perma.cc/3SY7-HJA/E] (summarizing the results of PJM’s 2017 auction). The reason PJM’s auction for 2017 secured capacity for 2020/2021 is that the grid operator runs capacity auctions three years in advance. See PJM MANUAL S8: PJM CAPACITY MARKET, supra note 204, at 18 ("The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year.");

271 See PJM, supra note 270, at 1 (stating that the target reserve margin for the same period was 16.6%).

272 See id. (stating that at 165,109.2 megawatts produced, PJM’s RPM cleared its target reserve level by 6.7%, or the equivalent of about 11,000 megawatts).


274 See ISO New-England, 162 FERC ¶ 61,205, slip op. at 38 (Mar. 9, 2018) (describing the risk of price suppression in the context of an environment with overcapacity).

275 See Rob Gramlich & Michael Goggin, Sustainable FERC Project, Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform 6-7 (2019), https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf [https://perma.cc/KV6C-74CM] ("PSO, ISO-NE, and NYISO have large excess reserve margins . . . . A rough estimate of the cost of this excess capacity is around $1.4 billion per year across the three markets . . . .").
These rules tend to be justified as necessary for reliability but are often overbroad or unrelated to the Commission’s goals.

a. Performance Duration Requirements

Performance duration requirements have put energy storage resources, such as batteries, at an economic disadvantage in many capacity markets.276 These requirements might be justified if they were related to a legitimate regulatory goal, though we would prefer that utilities that have an incentive to keep costs down—not administrative bodies—determine the value of these resources. Duration requirements are usually justified as necessary to ensure that capacity units are available during peak demand.277 The problem with overly long duration requirements is that peak demand usually lasts only three or four hours, yet some regions stipulate that batteries cannot participate fully in capacity markets unless they can store electricity for ten hours.278 Yet batteries that can store electricity for four hours provide significant capacity benefits and reduce peak load.279 They should therefore be compensated for providing capacity.


277 See, e.g., ROB GRAMLICH, MICHAEL GOGGIN & JASON BURWEN, ENABLING VERSATILITY: ALLOWING HYBRID RESOURCES TO DELIVER THEIR FULL VALUE TO CUSTOMERS 22 (2019), https://gridprogress.files.wordpress.com/2019/09/enabling-versatility-allowing-hybrid-resources-to-deliver-their-full-value-to-customers.pdf [https://perma.cc/PCA8-S69K] (“The need for duration is a function of how long peak conditions last.”); St. John, supra note 276 (describing advocates’ argument against PJM’s ten-hour duration requirement, which relies on the fact that demand peaks “can presently be met by efficient dispatch of shorter-duration storage, given the current mix of supply resources”).

278 See, e.g., St. John, supra note 276 (describing PJM’s ten-hour requirement); see also SYS. PLANNING DEPT., PJM, PJM MANUAL 21: RULES AND PROCEDURES FOR DETERMINATION OF GENERATING CAPABILITY 24-25 (14th rev., effective Aug. 1, 2019), https://www.pjm.com/~i/media/documents/manuals/m21.aspx [https://perma.cc/P3EK-2XCL] (“All or any part of a unit’s capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 10 hours, shall be considered as unlimited energy capability.”).

279 See KEVIN CARDEN ET AL., ASTRAPÉ CONSULTING, CAPACITY VALUE OF ENERGY STORAGE IN PJM 2 (2019), https://www.astrape.com/astrape-capacity-value-of-energy-storage-in-pjm [https://perma.cc/QGZ4-XB94] (“The results of our analysis demonstrate that with energy storage deployments up to 4,000 MW, 4 hours of duration allows those resources to provide full capacity value . . . . With energy storage deployments up to 8,000 MW, 6 hours of duration allows those resources to provide full capacity value . . . .”).
b. **Seasonal Commitment Periods**

A similar problem is that in many markets, resources are eligible for capacity payments only if they can perform year-round.\textsuperscript{280} Wind and solar produce more electricity at certain times of day and at certain times of the year.\textsuperscript{281} To reflect the fact that they are less reliable than other generators, grid operators reduce the capacity factor of these “Intermittent Resources” to reflect the average capacity they provide over the course of the entire year.\textsuperscript{282} As with performance duration requirements, administrators justify these regulations on the ground that they serve a legitimate goal—in this case, ensuring that capacity is available when needed.

Grid operators could provide the same level of reliability at lower cost by bifurcating capacity markets into summer and winter periods and developing separate performance requirements based on season.\textsuperscript{283} Peak demand tends to be higher in the summer, which also happens to be when solar arrays are able to operate at higher capacity.\textsuperscript{284} A seasonal commitment period would allow expensive resources such as coal-fired power plants to reduce their own costs by taking seasonal outages when demand for electricity declines.\textsuperscript{285} Generators that are needed at only certain times of the year would be able to mothball—to deactivate for a period of time—and turn on when they are needed.\textsuperscript{286} Seasonal commitment periods could provide the same level of reliability as year-round commitment periods while lowering costs and eliminating unnecessary capacity.\textsuperscript{287}

\textsuperscript{280} See PJM MANUAL 18: PJM CAPACITY MARKET, supra note 204, at 18 (discussing planned commitments in the unit of “Delivery Year[s]” and requiring “a constant load obligation” during that period).

\textsuperscript{281} See id. at 115 (noting seasonal variation in the generation capacity of renewable resources such as wind, solar, landfill gas, and hydroelectric power).

\textsuperscript{282} See, e.g., id. at 115-16 (describing PJM’s test for calculating the expected output of “Intermittent Resources . . . such as wind, solar, . . . and other renewable resources” by measuring how many megawatts these resources produce during defined periods in the summer and winter).

\textsuperscript{283} See, e.g., id.


\textsuperscript{285} See SAM NEWELL ET AL., BRATTLE GRP., OPPORTUNITIES TO MORE EFFICIENTLY MEET SEASONAL CAPACITY NEEDS IN PJM 11-12 (2018), http://files.brattle.com/files/13723_opportunities_to_more_efficiently_meet_seasonal_capacity_needs_in_pjm.pdf [https://perma.cc/M4P5-HUKQ] (describing how a seasonal approach that, for example, would give higher capacity ratings to wind energy in the winter and solar energy in the summer, would enable producers to better match demand).

\textsuperscript{286} See id. at 12 n.22 (proposing giving “[a]nnual resources . . . the option to offer at a different price to clear based on a 6-month summer-only or winter-only capacity obligation,” which “would allow for a seasonal export or mothballing arrangement”).

\textsuperscript{287} Id. at 8-16.
According to one advocacy group, the failure to “address variations in seasonal peak loads . . . creates an inefficiency—the market sends signals for investment in year-round capacity even though the existing year-round capacity combined with seasonal resources might be able to meet the demand at all times during the year.”

In PJM, a seasonal capacity market could create an estimated $100 to $600 million per year in societal benefits.

c. Discounting Renewables

Another problem with capacity market rules is that wind and solar generators receive lower capacity ratings than conventional generators. Again, the rationale for these rules, that intermittent resources are less reliable than other resources, is a sensible response to a genuine reliability concern. Grid operators, however, rely on crude and unsophisticated valuation techniques that excessively discount renewables. A PJM renewable integration study showed that methods for calculating capacity used in different grid operators resulted in dramatically different capacity factors for the same resources.

PJM, for example, proposed in 2018 to reduce wind’s capacity value from thirteen percent to around eight percent of “nameplate capacity” based on its calculation of median output during critical hours. More sophisticated analyses calculate a generator’s capacity factor by establishing the probability that an individual resource will be available when it is actually needed. Using this method, PJM found that it could substantially increase the capacity factor of wind and solar.

Not only do the rules described in this Section undercompensate clean energy and storage resources for services that they provide to the grid, but they also lead to excess capacity and high prices. Some clean energy and storage resources will enter the market despite being excluded from capacity.

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289 NEWELL ET AL., supra note 285, at 15.


292 See id. at 27-28 (describing the use of such studies by PJM and MISO, which resulted in wind capacity values of 15-20% and solar capacity values of 55-65%).

293 Id.
markets. The owners of these resources may conclude that they can cover their costs entirely through long-term bilateral contracts, that they can recover costs from energy markets, or that state subsidies make up for unfavorable capacity market policies. Because such resources provide electricity during peak demand, they support resource adequacy. However, the capacity markets additionally incentivize non-clean energy or storage resources to provide the same resource adequacy. In this way, mandatory capacity markets forces the procurement of redundant resources beyond the level necessary for a reliable supply of electricity. The added cost for this waste falls on consumers.

The rules described above are not a comprehensive list of capacity market rules that make it difficult for new resources to compete with incumbents, and other parts of electricity markets also exhibit a bias against renewables. They do, however, show that capacity markets rely on administrative decisions to determine the value of resources. FERC and the grid operators identify a critical characteristic but, rather than support a market that would compensate any generator that could provide that service, they ensure that such generators receive revenues sufficient to recover their costs regardless of whether or not they are actually needed. Like cost-of-service regulation, these rules shield incumbent generators from competition and retain resources even when cheaper alternatives are available to take their place.

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294 See Christina Simeone, Understanding the Challenges of Integrating Seasonal Resources into PJM’s Wholesale Capacity Market, KLEINMAN CTR. FOR ENERGY POL’Y (June 20, 2016), https://kleinmanenergy.upenn.edu/policy-digests/understanding-challenges-integrating-seasonal-resources- pjm%E2%80%99s-wholesale-capacity [https://perma.cc/E7TV-GSGZ] (explaining that in the 2018/2019 and 2019/2020 Base Result Auctions, only 80% of total market resources are eligible under the PJM Capacity Performance Requirement, which determines which resources qualify for capacity payments).

295 See id. (“It is expected that the [Capacity Payment Requirement “pay-for-performance” model] will incent generators to secure fuel supplies, add dual-fuel capabilities, help protect operations in extreme weather events, and will largely provide economic benefits to resources that are available year round.”).


2. Structural Challenges with Capacity Markets

On a more fundamental level, capacity markets are problematic because they overcompensate outdated resources and do not actually procure the resources needed to meet demand. FERC seems to treat capacity markets as a stand-in for reliability. There are two problems with this approach. First, because capacity is only one of a number of qualities needed to support a reliable power grid, the failure of capacity markets to actually compensate resources needed for reliability leads to additional interventions, which are described in Sections IV.B and IV.C. Second, capacity markets protect incumbents by requiring uneconomic incumbent generators to continue to operate even when less expensive units become available. Capacity markets thus procure generation with the wrong attributes (they do not reward operating even when less expensive units become available. Capacity markets protect incumbents by requiring uneconomic incumbent generators to continue to operate even when less expensive units become available. Capacity markets thus procure generation with the wrong attributes (they do not reward

a. Capacity Is Not Reliability

Capacity markets often predict demand three years in advance and retain enough supply to meet that demand, yet they fail to sufficiently distinguish between different types of capacity. Grid reliability can be threatened for many reasons. Sudden spikes in demand require generators to increase supply quickly. Generators located in certain areas may be especially valuable because they reduce congestion on transmission lines. Not all supply procured in capacity markets will provide these services, and capacity markets


299 See, e.g., Capacity Market (RPM), supra note 298 (stating that by conducting procurement years in advance, PJM ensures “long-term grid reliability”).

300 See id. (defining capacity generally as “a commitment of resources to deliver when needed”).


302 PJM does separate its capacity market into subregions and generators that provide capacity in resource-constrained areas receive greater capacity payments. See PJM MANUAL 18: PJM CAPACITY MARKET, supra note 294, at 23-26. Still, because these payments are administratively determined and remain stable over a three-year period, generators that received a premium for reducing congestion will be compensated for doing so even after they stop providing that service. See id. at 110 (“The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year.”).
will therefore overcompensate inflexible units because they provide the same level of compensation to inflexible generators as to flexible ones.\textsuperscript{303}

By contrast, when energy markets provide a large percentage of revenue, prices increase to reward needed services.\textsuperscript{304} A generator that can quickly supply more electricity to meet a spike in demand or reduce transmission congestion will collect revenues from energy markets for providing those services.\textsuperscript{305} However, when generators are retained years in advance in capacity auctions, they receive compensation for providing a single service that is necessary but not sufficient to support a reliable grid. As energy markets provide a smaller share of total revenue, their ability to reward flexible units diminishes. When critical generators retire, regulators intervene in the ways described in Sections IV.B and IV.C.

b. Uneconomic Incumbent Generators

A related concern is that mandatory capacity markets delay the retirement of uneconomic generation. By procuring generation years in advance and imposing barriers to exit for generators that clear capacity auctions, mandatory capacity auctions lead to excess capacity and high prices.\textsuperscript{306} That is in part because resources may enter the market—and provide capacity—even when they did not clear the capacity auction. Since the resources that did clear the capacity auction have committed to operating in that period, and since the capacity auction did not account for the resources that did not clear the capacity auction, mandatory capacity markets will tend to procure excess capacity.

In recent years, the price of natural gas and renewables has declined significantly.\textsuperscript{307} However, because generators commit to operate three years

\textsuperscript{303} See GRAMLICH \& GOGGIN, supra note 275, at 11-12 ("[T]he crude definition of capacity does not distinguish between flexible and inflexible resources, and many fossil and nuclear resources that receive large capacity payments provide little to no flexibility.").

\textsuperscript{304} See GOGGIN ET AL., supra note 291, at 12 (explaining that while energy sales currently produce the most revenue in wholesale electricity markets, increased use of renewables will have an overall effect of reducing energy prices).

\textsuperscript{305} See id. ("Frequency regulation and reactive power are among the most valuable reliability services.").

\textsuperscript{306} See PJM Capacity Prices Nearly Double in Most Territories, ENERGYWATCH (June 12, 2018), https://energywatch-inc.com/pjm-capacity-prices-nearly-double [https://perma.cc/AZT5-CDAG] (identifying the reception of fewer bids from newer resources as one reason for higher capacity prices in the PJM region).

\textsuperscript{307} See LAZARD, supra note 226, at 7 (showing that the levelized cost of energy (LCOE) for solar photovoltaic energy fell from $3.59 per megawatt-hour in 2009 to $0.40 per megawatt-hour in 2019, that the LCOE for wind fell from $1.35 per megawatt-hour in 2009 to $0.41 per megawatt-hour in 2019, and the LCOE of combined cycle gas fell from $0.83 per megawatt-hour in 2009 to $0.56 per megawatt-hour in 2019).
in the future, ratepayers were stuck paying for uneconomic capacity. For example, natural resources have entered markets that have too much capacity, and they have done so at rates that exceed the rate at which generators have left the market. The fact that markets that rely on capacity markets continue to procure additional electricity even when there is no need to do so suggests a market failure. Nonetheless, generators that cleared capacity markets agreed to operate until their capacity commitment ended, despite the fact that bloated reserve margins indicates that they were no longer needed to support regional capacity goals.

This dynamic resembles traditional cost-of-service regulation. In both systems, regulators identify the generators that are needed to meet future demand and guarantee those generators revenues sufficient to cover their costs. In exchange, the generators agree to provide service for a certain period of time. Like cost-of-service regulation, the regulatory interventions shield incumbent generators from competition, lead to excess capacity, and increase prices.

B. From Capacity Markets to Fossil Fuel Protectionism

As the previous Section showed, mandatory capacity markets fail to actually procure flexible resources needed for reliability. Regulators have responded by intervening to maintain resource adequacy, but with the effect of inefficiently and unnecessarily protecting fossil fuel generators. Specifically, in 2018, two grid operators—ISO-NE and PJM—took aggressive steps to further bolster fossil fuel generators. In both cases, FERC felt that an administrative intervention was necessary to protect “investor confidence” or the “market’s integrity.” It is not clear that these regulatory interventions are even necessary. If these interventions are pretextual and not necessary to maintain reliability, they reveal a willingness to expand administrative pricing and shift further away from competitive markets to paper over capacity

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308 See GOGGIN ET AL., supra note 291, at 27 (stating that procurement three years in advance can fail to map onto actual demand).
309 This phenomenon of mismatch between procurement and demand levels has been particularly acute in the PJM market. Id.
310 See GRAMLICH & GOGGIN, supra note 275, at 7-10.
311 See id. at 6-7.
312 See Calpine Corp., 163 FERC ¶ 61,236, slip op. at 65 (June 29, 2018) (justifying its holding that PJM’s existing tariff was unduly discriminatory by stating that the PJM plan risked the creation of price distortions which “compromise the capacity market’s integrity”); ISO New England, Inc., 162 FERC ¶ 61,205, slip op. at 9 (Mar. 9, 2018) (“Ultimately, the purpose of basing capacity market constructs on these principles is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates.”). But see Calpine Corp., 163 FERC ¶ 61,236 (Glick, Comm’r, dissenting), slip op. at 4 n.6 (criticizing FERC for focusing on “investor confidence” as the critical issue in its earlier order on ISO-NE’s proposal and then shifting, without explanation or serious mention of “investor confidence,” to a new market “integrity” standard in its order on PJM).
market flaws. And to the extent that they respond to any revenue adequacy problem, they do so only because FERC and grid operators fear that existing market designs cannot accommodate state subsidies without jeopardizing the financial stability of resources actually needed for a reliable power grid.

As this Section shows, concern that capacity markets do not actually secure reliability has driven FERC and grid operators to make it difficult for renewable resources to access capacity markets. FERC has argued that it is necessary to impose barriers to entry that limit renewables’ ability to participate in capacity markets in order to correct the distortions caused by state renewable subsidies.\(^{313}\) The Commission seems to be concerned that state subsidies undermine the Commission’s idealized view of capacity markets,\(^{314}\) though as the previous Section showed, capacity markets themselves are rife with administrative decisions about the relative value of different resources. It is difficult to understand how state subsidies create “financial stresses” and “compromise the ultimate goal of the capacity market to provide investor confidence to attract new entry and assure resource adequacy”\(^{315}\) in a manner that is different from capacity market pricing decisions that themselves determine winners and losers.

The implication is that FERC, ISO-NE, and PJM do not trust capacity markets to procure the services needed for reliability. If capacity markets fail to procure resources that can ease congestion in transmission lines or that provide needed flexibility services, those failures will become more pronounced as renewables provide a greater share of electricity—and they

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\(^{313}\) See Cullenward & Welton, supra note 115, at 108 n.6 (noting that the Second and Seventh Circuits have accepted FERC’s position that the Commission can “impose punitive wholesale electricity market designs”). These views are supported by FERC’s assertion that capacity markets “have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market.” See Calpine Corp., 163 FERC ¶ 61,236, slip op. at 3.

\(^{314}\) PJM has stated:

As a consequence of steadily declining energy prices, certain coal and nuclear units in PJM have become economically challenged . . . . Many state policymakers have, therefore, either acted or are considering the possibility of acting to provide subsidies to nuclear and coal resources to ensure they remain in operation. If not mitigated, PJM shares the view of the [Independent Market Monitor] in the 2017 State of the Market Report that subsidies are contagious and could spread. In effect, subsidies tend to suppress market prices and broaden the financial stresses that triggered subsidies in the first place. If subsidies do become more widespread, they could compromise the ultimate goal of the capacity market to provide investor confidence to attract new entry and assure resource adequacy.

\(^{315}\) Id.
will do so regardless of whether renewables benefit from state subsidies. The MOPRs described in this Section and the RMR agreements described in the next Section can thus be partly understood as poorly designed interventions to raise revenues for specific resources deemed critical to the grid. A superior solution would rely on competitive procurement mechanisms—not economic protectionism—to retain critical services.

1. ISO-NE

In early 2018, ISO-NE proposed, and FERC approved, a two-stage capacity auction designed to ensure resource adequacy.316 In the first stage, state-supported renewables must submit bids at an administratively determined price.317 This is the “minimum offer price” known as the MOPR.318 Even if renewables could operate profitably if they submitted lower bids, the MOPR prohibits state-supported renewable resources from making low bids that would suppress capacity market prices. The MOPR will likely prevent state-sponsored resources from clearing the first stage of ISO-NE’s capacity auction.319

Resources that clear the first stage of the capacity auction can declare that they would be willing to retire if compensated for doing so.320 At that point, renewables can purchase these resources’ capacity commitments. To do so, they must be willing to buy out the generators that are willing to retire.321 This requirement forces renewables that would have been willing to provide low-cost electricity to buy out outdated fossil fuel generators. This, in turn, discourages the entry of renewables and subsidizes incumbents. If a fossil fuel generator is able to provide capacity at the same rate as the renewable, the fossil fuel generator will clear the auction because it is able to enter during the first stage.

This market design also makes it easier for new fossil fuel generators to enter the market than renewables. Under ISO-NE’s new capacity market rules, generators can be pushed out of the market in one of two ways. First, a renewable generator can purchase capacity from an older generator in the

317 ISO-NE’s tariff says that a “Sponsored Policy Resource” is any zero-carbon resource that receives “an out-of-market revenue source.” Id. at 3 n.6 (quoting ISO New England’s proposed Tariff § I.2.2).
318 Id. at 2–3.
319 Id.
320 Partial Protest and Comments of the Massachusetts Attorney General at 2, ISO New England, Inc., 162 FERC ¶ 61,205 (2018) (No. ER18-619-000) (“The practical effect of [the rule] is that sponsored policy resources have a strong likelihood of not clearing in the FCM . . . .”).
322 See Cullenward & Welton, supra note 115, at 114 (explaining this mechanism).
second stage of the auction at a price named by the retiring generator. Alternatively, a generator not subject to the MOPR—in other words, a fossil fuel or nuclear generator—can submit a bid in the first stage of the capacity auction. If that bid clears, the new fossil fuel generator eliminates the need for the old coal-fired power plant, which means that the old generator does not clear the auction and will retire. In that case, there may be no opportunity for renewables to receive revenues from capacity markets because the new generator may refuse to participate in the second stage of the auction. Thus, not only does the MOPR provide a handout to inefficient fossil fuel generators, but it also distorts markets, discourages the entry of renewables, and redistributes revenue from renewables to fossil fuel generators.

ISO-NE’s MOPR also leads to excess capacity. Renewables may ultimately enter the market even if they cannot participate in capacity auctions. They may do so because they feel that they will recover their costs from energy markets, or because they have secured long-term bilateral contracts that provide them with sufficient revenues despite the fact that they will not be compensated for providing capacity. In such cases, ISO-NE will procure surfeit supply because it does not factor the renewables that did not participate in capacity auctions into its load projections. Of course, doing so further increases rates as consumers are forced to pay for resources they do not need.

2. PJM

PJM has also tried to reform capacity markets to prevent renewables from suppressing generator revenues. PJM stakeholders failed to agree on a capacity market structure. As a result, PJM filed two alternative proposals with FERC in April 2018.

Under PJM’s preferred option, “Capacity Repricing,” the market operator would have run the market one time with “subsidized resource[s]” included at their self-determined bid price, to figure out which resources receive

323 See GRAMLICH & GOGGIN, supra note 275, at 10 (“MOPR . . . causes consumers to pay for redundant capacity—customers first pay for the construction of resources through state policy, but when that is unable to clear the capacity market due to the MOPR, customers are forced to buy an equivalent amount of capacity that does clear in the capacity market.”).

324 Id.

325 See Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market at 7, PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) (No. ER18-1314-000) (reporting that stakeholders were divided between two alternatives, resulting in neither alternative receiving the two-thirds vote the measure it required for endorsement).

326 See id. at 17-18 & n.40; see also id. at 5-6 (providing an overview of the two alternatives and the process by which PJM submitted them for FERC review).
capacity obligations.\textsuperscript{327} PJM would then run the auction a second time but would exclude all resources that did not clear the first time. Any resource that received a state subsidy would be “repriced to a competitive level” in the second auction.\textsuperscript{328} This approach would increase prices but would arguably undo the price suppression caused by state subsidies. Every generator that cleared the first auction would be paid the higher clearing rate that resulted from the second auction.\textsuperscript{329}

Alternatively, PJM proposed extending its “minimum offer price rule extension” (“MOPR-Ex”)—which had previously required some resources to submit mandated minimum bids—to state-supported resources, but also providing an exception to resources needed specifically to meet state renewable portfolio standards.\textsuperscript{330} Under this proposal, covered renewables would clear the capacity market only if they were cost-competitive with other resource types after factoring out any state support.\textsuperscript{331}

FERC rejected both of PJM’s proposals and, after a year-long delay, ordered PJM to expand its MOPR, effectively setting an administrative price on all resources that receive state subsidies.\textsuperscript{332} When it rejected PJM’s proposal, the Commission determined that the “Capacity Repricing” option overcompensated renewables because it would allow them to “receive the same clearing price as competitive resources” even though those resources “would then further benefit from the higher price set in stage two of the auction.”\textsuperscript{333} This proposal, the Commission explained, would “increase prices for load, and then pay this higher price as a windfall to the very same resources that initially caused the price suppression PJM is attempting to correct.”\textsuperscript{334}

FERC found that the MOPR-Ex proposal would also lead to unjust and unreasonable rates.\textsuperscript{335} Fatal to the MOPR-Ex was that it permitted “disparate treatment between resources receiving out-of-market support through RPS programs and other state-supported resources.”\textsuperscript{336}

\textsuperscript{327} Id. at 42.
\textsuperscript{328} Id. at 42-43.
\textsuperscript{329} Id. at 42-43, 51.
\textsuperscript{330} Id. at 43; see also id. at 15 (describing both of PJM’s proposals as creating certain “non-actionable” subsidies).
\textsuperscript{331} See id. at 43.
\textsuperscript{333} See Calpine Corp., 163 FERC ¶ 61,236, slip op. at 30 (June 29, 2018).
\textsuperscript{334} Id.
\textsuperscript{335} See id. at 47 (“PJM has not met its section 205 burden to show that MOPR-Ex is just and reasonable, and not unduly discriminatory.”).
\textsuperscript{336} Id.
The Commission ultimately determined that “out-of-market payments provided . . . by states . . . threaten the competitiveness of the capacity market administered by PJM.”\textsuperscript{337} FERC therefore directed PJM to “extend[] the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments.”\textsuperscript{338} Such an expansive MOPR, the Commission reasoned, is necessary “to mitigate the impact of State Subsidies on the capacity market.”\textsuperscript{339} FERC’s definition of “[s]tate [s]ubsidy,” its term for the subsidies subject to the MOPR, could encompass most resources that participate in PJM auctions. Commissioner Glick wrote that the “sweeping definition of subsidy” is so broad that it “will potentially subject much, if not most, of the PJM capacity market to a minimum offer price rule.”\textsuperscript{340} FERC’s concern about price suppression caused by state subsidies thus induced the Commission to impose a system of administrative pricing on a market that is already subject to strict regulatory oversight.\textsuperscript{341}

According to analysts, the purpose of capacity markets is to procure sufficient supply at low cost.\textsuperscript{342} The Commission’s Order is ostensibly based on concern that state subsidies “threaten the competitiveness of the capacity market administered by PJM,” and so it ordered PJM to replace a market that was already subject to a high degree of regulatory control with a system in which administrators affirmatively select which resources clear capacity auctions (and thus which resources enter and exit the market).\textsuperscript{343}

\textsuperscript{337} Calpine Corp., \(169 FERC \# 61,239\), slip op. at 2 (Dec. 19, 2019).
\textsuperscript{338} Id. at 3.
\textsuperscript{339} Id. at 66.
\textsuperscript{340} Calpine Corp., \(169 FERC \# 61,239\) (Glick, Comm’r, dissenting), slip op. at 1. The full definition of “material subsidy” seems to cover any resource that receives any sort of state support:


PJM proposes to define a “Material Subsidy” to include: (1) material payments, concessions, rebates, or subsidies as a result of any state-governmental action connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support that has the effect of allowing the unit to clear in any [PJM capacity auction]) of a Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support that has the effect of allowing the unit to clear in any [PJM capacity auction]), of the Capacity Resource.”

\textsuperscript{341} Id. at 28-29 (quoting Initial Submission of PJM Interconnection, L.L.C. at 19-20).
\textsuperscript{342} Id. at 32-33; see also supra Section IV.B (discussing capacity markets).

See Calpine Corp., \(169 FERC \# 61,239\), slip op. at 4 (“We affirm our initial finding that [a]n expanded MOPR with few or no exceptions, should protect PJM’s capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are
If grid operators were allowed to incorporate renewables into capacity auctions, they would procure the correct amount of supply at lower cost than they do now. There is no reason that capacity markets are unable to accommodate state subsidies. If state subsidized resources participated in capacity markets and suppressed prices, they might drive some incumbent suppliers out of the market. In the event that the participation of these subsidized resources led to an inadequate supply of resources, capacity prices would rise to incentivize new entry. Thus, while FERC has declared that price suppression undermines market “integrity,” the Commission has failed to explain how the indeterminate and undefined goal of market integrity relates to the actual goal of maintaining sufficient load.

Financial analysts have estimated that these MOPRs will cost billions annually. FERC itself has acknowledged that capacity market reforms will raise prices for consumers and lead to excess capacity. It has defended these

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not able to offer below a competitive price.” (quoting Calpine Corp., 163 FERC ¶ 61,236, slip op. at 69 (June 29, 2018)).

344 See BIALEK & UNEL, supra note 288, at 18 (“[E]ven if externality payments reduce capacity prices in the short term, capacity markets are designed to adjust to that change and keep prices at a level necessary to ensure resource adequacy.”).

345 See Calpine Corp., 169 FERC ¶ 61,239, slip op. at 22 (“The June 2018 Order thus found PJM’s existing MOPR provisions unjust and unreasonable and unduly discriminatory because they failed to protect the ‘integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts . . . .’); see also Calpine Corp., 163 FERC ¶ 61,236 (Glick, Comm’r, dissenting), slip op. at 4 n.6 (suggesting that the Commission has failed to define “integrity” of the market”).

346 Protest of Clean Energy Advocates, supra note 3, at 7; Affidavit of Michael Goggin, Grid Strategies LLC, at ¶ 3 (May 7, 2018) (included in Appendix B to Protest of Clean Energy Advocates, supra note 3); MICHAEL GOGGIN & ROB GRAMLICH, CONSUMER IMPACTS OF FERC INTERFERENCE WITH STATE POLICIES (2019), https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf [https://perma.cc/BQFJ-66LP] (“We estimate the total cost of the MOPR to PJM consumers could reach $5.7 billion per year, a 60% increase in cost compared to the current capacity market.”); Memorandum from Monitoring Analytics to PJM Market Participants (Sept. 17, 2019), http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Response_to_Grid_Improvements_Report_20190921.pdf [https://perma.cc/R6XF-P793] (disagreeing with the specific number reached in the Goggin and Gramlich report’s analysis but finding that an earlier MOPR proposal could cost billions). Commissioner Glick estimated that PJM’s MOPR would cost at least $2.4 billion a year. Calpine Corp., 169 FERC ¶ 61,239 (Glick, Comm’r, dissenting), slip op. at 23.

347 See Calpine Corp., 169 FERC ¶ 61,239, slip op. at 23 (“As to arguments that an expanded MOPR will . . . increase costs to consumers, courts have directly addressed this point, holding that states are free to make their own decisions regarding how to satisfy their capacity needs, but they ‘will appropriately bear the costs of [those] decisions,’ . . . including possibly having to pay twice for capacity.” (quoting N.J. Bd. of Pub. Utils. v. FERC, 744 F.3d 74, 96–97 (3d Cir. 2014) (alterations in original)); see also Request for Rehearing of Clean Energy Advocates at 1, ISO New England Inc., 162 FERC ¶ 61,205 (2018) (No. ER18–619–000) (arguing that “[t]he predictable result” of ISO-NE’s adoption of a CASPR mechanism, which clean energy advocates attributed to “FERC’s decision to close its eyes,” is that “thousands of megawatts of clean energy will be barred from
reforms, however, by claiming that price suppression undermines investor confidence, and that it is necessary to charge consumers high prices for capacity they do not need to mitigate investor squeamishness. Incidentally, this is the same justification that public utility commissions rely on for setting regulated rates. An administrative intervention to bolster investor confidence is, however, anathema to the idea of competitive markets.

When utilities were regulated as natural monopolies, investor confidence was a means to maintaining reliable electricity by ensuring a return on investments in utilities’ rate base. But the rate regulation system does not ensure the optimal procurement of the lowest cost resources. Today, PJM and ISO-NE have excess fossil fuel capacity. Immunizing the shareholders of these fossil fuel generators certainly prevents those generators from retiring and ensures the returns on investment for those shareholders. But in doing so, it sacrifices the core imperative of a competitive market, subjugating the interests of consumers and new generators to the interests of the incumbent generators. If FERC really is concerned about reliability, all it has to do is permit capacity prices to rise, in which case the markets would procure sufficient supply.

PJM notes that advocates of its MOPR-Ex proposal “hope that it will work to dis-incent states from providing subsidies in the first instance” by making it prohibitively expensive for states to meet their energy goals—likely increasing the costs of state renewable policies by hundreds of millions of dollars. PJM even acknowledged at one point that FERC’s proposed MOPR could leave states with “no practical option to pursue generation-related public policy goals through subsidy.” Some stakeholders thus accessing the ISO-NE capacity market, and the region’s customers will be forced to spend vast sums to buy an equivalent amount of redundant capacity”).

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348 See, e.g., Calpine Corp., 163 FERC ¶ 61,236, slip op. at 64-65 (holding PJM’s Tariff to be “unjust and unreasonable and unduly discriminatory” for failing to protect the capacity market from price distortions, which undermine investors’ ability to predict how their investments will perform).

349 Fed Power Comm’n v. Hope Nat. Gas Co., 520 U.S. 741, 786 (1997) ("The return . . . should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital . . . . Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid.").


351 Capacity Repricing or in the Alternative MOPR-Ex Proposal, supra note 325, at 56 n.138.

352 See Protest of Clean Energy Advocates, supra note 3, at 1 (explaining that both of PJM’s proposals, including the MOPR-Ex, would “saddle consumers with billions in extra costs . . . .”).

353 Initial Submission of PJM Interconnection, L.L.C. at 6, Calpine Corp., 169 FERC ¶ 61,239 (2019) (Nos. EL16-49-000, EL18-1314-000, -001, EL18-175-000).
explicitly view PJM’s MOPR not as a way of ensuring grid reliability, but as a device to make it too expensive for states to pursue clean energy policies.354

C. Reliability-Must-Run Agreements

While FERC’s decision to limit or exclude renewables from capacity markets implicitly raises many of the same problems as rate regulation, in some instances FERC and the grid operators have gone further and explicitly restored rate regulation for certain generating units. In order to retain critical generating units, FERC has insisted that grid operators develop a process for designating generators “reliability-must-run” (RMR) units.355 Unlike capacity auctions, these RMR policies do not even invoke the specter of competition but are rather explicitly designed to respond to market failures.

Although RMR agreements have existed for years,356 these contracts received heightened scrutiny in December of 2018 after ISO-NE used an RMR agreement to bail out a large gas plant.357 On December 20, 2018, FERC voted to approve cost recovery for Exelon’s Mystic Generating Station.358 This order gave the natural gas power plant ratepayer-financed contracts through May 2024.359 Despite the fact that New England has restructured its electricity market, ISO-NE determined that the plant was essential for grid reliability because it supports the Everett liquefied natural gas facility, which is a critical source of fuel for the region.360 It therefore agreed to allow the facility to recover its costs.361

FERC’s approval of the Mystic cost-of-service agreement was especially surprising in light of the fact that Massachusetts, one of the states that would

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354 Capacity Repricing or in the Alternative MOPR Ex Proposal, supra note 325, at 56 n.138.
355 See N.Y. Indep. Sys. Operator, 150 FERC ¶ 61,116, slip op. at 1-3 (Feb. 19, 2015) (directing NYISO to develop RMR agreements); PJM Interconnection, L.L.C., 107 FERC ¶ 61,112, slip op. at 17 (May 6, 2004) (directing PJM to “develop a policy which would provide a reasonable opportunity for recovery of going forward costs,” which could include RMR contracts or capacity payments); see also Cal. Indep. Sys. Operator Corp., 138 FERC ¶ 61,112, slip op. at 1-2 (Feb. 16, 2012) (acknowledging CAISO’s history of reliability controls).
356 See News Release: About the Reliability-Must-Run Agreement for Greens Bayou Unit 5, ERCOT (June 3, 2016), http://www.ercot.com/news/releases/show/98507 [https://perma.cc/WGP3-TAEZ] (“Since 2002, ERCOT has executed 73 other RMR agreements, of which 69 have been for the purpose of transmission stability.”) These agreements have generally been intended to stabilize the grid. Id.
357 See Constellation Mystic Power, LLC, 165 FERC ¶ 61,267, slip op. at 2, 12 (Dec. 20, 2018) (approving cost-of-service agreements between ISO-NE and Mystic, with the effect that “Mystic 8 and 9 will be operating for two years on a reliability must-run (RMR) basis”).
358 Id. at 2.
359 Id. at 6-8.
360 Id. at 4-6.
361 See id. at 17-19 (approving the cost-of-service agreement but expressing concern about the methodology used to calculate Mystic’s return on equity).
ostensibly experience resource adequacy challenges if the plant retired—submitted evidence questioning whether the plant was needed to maintain reliability in the region.\textsuperscript{362}

The Mystic cost-of-service agreement is a departure from previous reliability-must-run agreements because ISO-NE justified the agreement using concerns about fuel security and resource adequacy rather than transmission constraints.\textsuperscript{363} It is worth noting, though, that ratepayers have been supporting generators through RMR agreements since the early 2000s.\textsuperscript{364}

While grid operators do not always disclose the cost of RMR agreements, they appear to cost hundreds of millions of dollars annually. In addition to the Mystic bailout, FERC recently approved a cost-of-service agreement for a California gas plant that put tens of millions of dollars of costs onto ratepayers.\textsuperscript{365} MISO and PJM both report numerous multimillion-dollar RMR agreements through 2024, though the lack of standardized reporting practices makes it difficult to obtain data on the actual costs of each RMR agreement.\textsuperscript{366} Texas used an RMR agreement to bail out a natural gas power plant near Houston.\textsuperscript{367}

FERC, moreover, seems prepared to extend RMR agreements. While one may be tempted to dismiss the Mystic agreement as a one-off, FERC recently approved a CAISO tariff filing that gives the ISO authority to enter into an


RMR agreement “to address any reliability need.” Commissioner Glick warned that FERC thereby gave CAISO “near-carte blanche discretion to enter into out-of-market contracts without review by the Commission” and authorized an “end-run around the Commission-approved market structures.” Commissioner Chatterjee has suggested that a mechanism similar to RMR agreements be used to support financially distressed coal-fired power plants.

It is entirely possible that every one of the units subject to the RMR agreements described above is necessary for grid reliability. FERC, however, need not rely on RMR contracts to retain these units. FERC and the grid operators wrongly assume that they should bail out the shareholders and creditors of every generator needed for reliability. If a critical generating unit claims that it will retire unless FERC approves a cost-of-service contract, state regulators should oversee an auction in which parties submit bids to purchase the assets. The entity that agreed to provide the services at least cost would be able to do so. In this way, essential generators would not be able to strong-arm regulators into passing the company’s market risk from investors to ratepayers.

Fifteen years ago, an analyst proposed that FERC develop this process when PJM inaugurated its capacity market. FERC rejected the proposal because it did “not treat all capacity suppliers equally.” The Commission justified this decision by claiming that “[i]n a competitive market, all suppliers will be paid the same price.” FERC felt that a unitary capacity payment better approximated a real market. Yet this system’s failure to retain the resources FERC needs has forced intrusive interventions that pay some suppliers more than others. These interventions would be unnecessary if FERC recognized that capacity markets do not procure the services the grid needs, and that it is important to support markets for these other qualities.

369 Id. (Glick, Comm’r, dissenting), slip op. at 1, 3.
371 For one example, see R. Moreno et al., Auction Approaches of Long-Term Contracts to Ensure Generation Investment in Electricity Markets: Lessons from the Brazilian and Chilean Experiences, 38 ENERGY POL’Y 5758, 5761-63 (2010).
373 PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, slip op. at 32 (Dec. 22, 2006).
374 Id.
375 See id. (determining that a capacity market with a downward sloping demand curve “better approximates a market”).
D. The Slippery Slope to Reregulating Generation

If policymakers continue to maintain reliability by subsidizing individual generators and excluding disfavored resources from important markets, they will quickly reregulate all power generation. The interventions described above create a positive feedback loop. One set of uncompetitive generators receives a subsidy, which suppresses energy market prices. Suppressed prices render another set of generators uncompetitive. Those generators then appeal to policymakers for an additional subsidy and the cycle continues.

This dynamic has begun to play out in several markets. The proliferation of low-marginal-cost natural gas plants and zero-marginal-cost renewable power has made many nuclear power plants uncompetitive.\(^{376}\) In response, nuclear power plants have emphasized their zero-carbon and reliability attributes.\(^{377}\) Rather than permit these plants to go out of business, several states have responded by agreeing to subsidize nuclear facilities.\(^{378}\) New York’s program alone is expected to cost $500 million,\(^{379}\) an Illinois program is projected to cost $235 million,\(^{380}\) and a New Jersey program could cost $300 million.\(^{381}\)

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This support allows nuclear power plants to submit low bids in both energy markets and capacity markets. That, in turn, further suppresses clearing prices and threatens the economic viability of coal and natural power gas plants. Coal representatives have responded by arguing that they are essential to reliability because they can store onsite coal that can be used when other resources are unavailable. This is the argument the DOE embraced when it proposed bailing out coal and nuclear power plants. Natural gas power plants may argue that their fast-ramping characteristics—the ability to respond quickly to a spike in demand or loss of supply—make them essential for a high-renewables grid. State or federal policymakers may be convinced and grant support to these generators. The Mystic bailout suggests that FERC has already begun to shield natural gas power plants perceived to be critical to reliability.

What emerges is a situation in which regulatory favor—not market forces—determines which resources are viable. As soon as a regulator concludes that a certain resource provides a critical service, it introduces a subsidy to support that resource. The subsidy suppresses energy and capacity prices, which further decreases the revenues other resources enjoy. That, in turn, increases the need for additional administrative interventions. PJM recently expressed concern about this phenomenon when it said that “the spread of rent-seeking activities could tear apart the essential fabric of regional coordination in planning gravitating toward integrated resource planning.”

As noted in Section III.B, renewables are expected to provide a significant share of electricity in many areas in the near future. If natural gas begins to receive state support—if, for example, RMR agreements become more common—then close to one hundred percent of overall generation would be receiving out-of-market support. Alternatively, if capacity markets continue to become a vehicle to support natural gas and coal power plants, then the entire industry will already be sustained to a significant degree through individual subsidies designed to protect particular resources.


385 See supra Section III.B. 
If this trend continues, electricity markets would no longer dictate energy prices. They would simply reflect regulatory preferences about which resources should stay in business. Rather than compete to provide inexpensive electricity, generators would compete for regulatory favor. The result closely resembles utility rate regulation. Part VI proposes alternative payments systems that would more efficiently procure electricity. First, though, it is worth considering the legality of recent FERC interventions that support fossil fuel generators and counteract state clean energy policies.

V. STATES AND THE FPA

In addition to the economic problems discussed above, interventions to prop up fossil fuel generators are stretching FERC’s jurisdiction to its limits. The legal basis for FERC’s authority to oversee grid reliability is Section 205 of the Federal Power Act (FPA), which requires the Commission to ensure that wholesale rates are “just and reasonable.”386 The FPA is clear that the Commission “shall not have jurisdiction . . . over facilities used for the generation of electric energy.”387 That authority is reserved for the states.388

In our view, the only way to resolve the tension between FERC’s authority over wholesale electricity prices and states’ authority over generating units is to clarify that FERC has authority to regulate reliability pursuant to its authority to regulate practices “affecting . . . rates,”389 but that federal jurisdiction over wholesale energy rates ceases when it prohibits states from regulating generation units. FERC regulations can increase the costs of state policies, but FERC cannot prevent states from acting to realize preferences for certain resources. Courts reviewing FERC reliability orders should consider whether the net effect of FERC policies is to prevent states from exercising that authority.

A. Federalism in the FPA

While FERC has begun to claim that it has plenary authority to ensure grid reliability, courts have unanimously embraced our view. When the Third Circuit upheld the Commission’s decision to develop a MOPR, the court did so not because the MOPR was necessary to support reliability, but because it was necessary to make sure wholesale energy prices—not capacity prices—

388 See id. § 824(a), (b)(i). For an extended analysis of the FPA’s federalist system, see Matthew R. Christiansen & Joshua C. Macey, Long Live the Federal Power Act’s Bright Line, 134 HARV. L. REV. (forthcoming).
remained just and reasonable. The Commission was concerned with buyerside market power. Specifically, it worried that utilities that owned transmission lines were manipulating energy markets by submitting artificially low bids in capacity markets. Owners of transmission lines are required to purchase a certain amount of supply from capacity markets. By submitting very low capacity bids, they purposefully suppressed capacity prices, thereby reducing the amount of money they were forced to spend to purchase capacity. Capacity markets and MOPRs were therefore justified to prevent manipulative behavior. The Third Circuit determined that FERC has jurisdiction to adopt MOPRs not because the Commission has plenary jurisdiction over markets for reliability, but because market manipulation in capacity markets is a “practice . . . ‘affecting’ rates.”

The courts that have reviewed capacity markets have been careful to point out that FERC should not weaponize its jurisdiction over markets for reliability to commandeer states’ authority over generation resources. In a case finding that FERC can oversee capacity markets, the D.C. Circuit clarified that this authority cannot conflict with states’ authority over generation facilities. As the court explained, while “the Commission may directly establish prices for capacity,” they cannot thereby prevent states from regulating generation facilities. The court went on to clarify that “[s]tate and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission.” That finding was embraced by the Supreme Court in 2016.

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391 Id. at 84-85; see also Richard B. Miller, Neil H. Butterklee & Margaret Comes, “Buyer-Side Mitigation in Organized Capacity Markets: Time for a Change?,” 32 ENERGY L.J. 449, 459-60 (2012) (explaining that buyer-side mitigation was originally designed to prevent market power abuses).
392 N.J. Bd. of Pub. Util., 744 F.3d at 85.
393 See id. (“When . . . LSEs buy more capacity than they offer into the auction, they have an incentive to keep auction prices as low as possible . . . . Such offers crowd out other capacity that is priced at a higher, cost-based rate, and thus result in a lower overall clearing price.”).
394 See id. (“To counteract that manipulation of the market, the MOPR seeks to identify uneconomic offers and ‘mitigate’ them by raising them to a price that more accurately approximates their net costs.”).
395 Id. at 98.
397 Id. at 481, 482.
398 Id. at 481.
399 See Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1298 (2016) (“States, of course, may regulate within the domain Congress assigned to them even when their laws incidentally affect areas within FERC’s domain.”); FERC v. Elec. Power Supply Ass’n, 136 S. Ct. 760, 775 (2016) (stating that FERC cannot “issue[] a regulation compelling every consumer to buy a certain amount

It is therefore perplexing that FERC has seemingly embraced an interpretation of the FPA that prevents states from exercising jurisdiction over their generation facilities—despite repeated admonitions of the courts that FERC's jurisdiction over capacity markets must further the Commission's goal of ensuring "just and reasonable" rates and accommodate state authority over generation.\textsuperscript{400} The interventions described in Part IV may be bad policy, but individually they may not excessively interfere with states' authority over generation.\textsuperscript{401} Altogether, though, these policies counteract state renewable policies. Insofar as they prevent states from realizing their resource preferences, they are in tension with D.C. Circuit precedent establishing that states retain authority to determine which generators enter and exit the market.\textsuperscript{402}

B. Recovering the FPA's Federalist Vision

To be sure, in the interventions described in the previous Parts, the Commission has claimed to recognize the need to respect the FPA's federalist vision.\textsuperscript{403} It is therefore surprising that FERC has taken such bold steps to counteract state policy decisions.\textsuperscript{404} When FERC ordered PJM to revise its MOPR, FERC cited its "statutory obligation, and exclusive jurisdiction, to ensure that wholesale capacity rates in the multi-state regional market are just and reasonable," and explained that the intervention was necessary to preserve "a capacity market that relies on competitive auctions to set just and reasonable rates."\textsuperscript{405} Yet as Part IV showed, the steps FERC has taken to accomplish these goals have had precisely the opposite result.

FERC has justified capacity market interventions by saying that these interventions are necessary to maintain "investor confidence" and "market

\textsuperscript{400} See 16 U.S.C. § 824(b)(1) (2018). Todd Aagaard and Andrew Kleit have argued that certain MOPR reforms ordered by FERC violate the FPA and Administrative Procedure Act. See Todd S. Aagaard & Andrew N. Kleit, A Road Paved with Good Intentions?: FERC's Illegal War on State Electricity Subsidies, 33 ELECTRICITY J., June 2020, at 1, 3-4 (2020).

\textsuperscript{401} Whether the rules are just and reasonable is another question. The fact that many of the rules described in Part IV have no conceivable justification may give rise to other legal challenges. The focus of this Article, however, is whether FERC actions suggest a power grab by the Commission. To that end, we focus on the federalism issue and bracket other legal challenges as outside the scope of this paper.

\textsuperscript{402} Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009).

\textsuperscript{403} See Calpine Corp., 169 FERC ¶ 61,239, slip op. at 6 (Dec. 19, 2019) ("Nor does this order prevent states from making decisions about preferred generation resources: resources that states choose to support, and whose offers may fail to clear the capacity market under the revised MOPR . . . will still be permitted to sell energy and ancillary services in the relevant PJM markets.").

\textsuperscript{404} Cf. 16 U.S.C. § 824(b)(1) ("The Commission . . . shall not have jurisdiction . . . over facilities used for the generation of electric energy . . . .").

\textsuperscript{405} Calpine Corp., 169 FERC ¶ 61,239, slip op. at 4, 6.
integrity.” But both New England and PJM have much more capacity than they need to provide reliable electricity. Given those circumstances, capacity markets should not give investors confidence that they will recover their costs. Doing so recreates the problems of cost-of-service regulation by guaranteeing shareholders a return on investment and shielding them from market risk. If these markets find themselves with insufficient resources, prices would rise regardless of whether some resources receive support from states.

FERC could be borrowing these terms from the Securities and Exchange Commission (SEC), which is the agency charged with protecting investor confidence and market integrity. FERC is, however, using these terms in a very different way. The SEC conceives of the goal of investor confidence as a procedural right. On its view, “[t]he laws and rules that govern the securities industry in the United States derive from a simple and straightforward concept: all investors, whether large institutions or private individuals, should have access to certain basic facts about an investment prior to buying it, and so long as they hold it.” Investor confidence is therefore ordinarily used to make sure that insiders do not have an unfair advantage over ordinary market participants— not to interfere with market signals created by legitimate state and federal policy decisions.

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406 See Calpine Corp., 163 FERC ¶ 61,236 (June 29, 2018) (Glick, Comm'r, dissenting), slip op. at 5-6 (observing that the majority order never defines market “integrity”); ISO New England Inc., 162 FERC ¶ 61,205 (Mar. 9, 2018) (Glick, Comm'r, dissenting in part and concurring in part), slip op. at 4-5 (questioning the aim of “investor confidence”).


408 See Bialek & UNEL, supra note 288, at 18 (explaining that capacity markets will “automatically adjust[]” in the event of an actual resource adequacy challenge).


410 Id.

411 See id. (describing how “investor confidence” is intended to create a level playing field for market participants).
Unlike the SEC, FERC has begun to use the goal of market “integrity” to justify administrative interventions that shield fossil fuel generators from market risk and immunize them from the effects of state clean energy policies. But if a market has procured sufficient supply, one might think that it is “unjust” and “unreasonable” to force consumers to pay to retain supply they do not need. In ordinary markets, shareholders and creditors are aware that they bear the risk that regulations can change in the future. Yet in electricity markets, grid operators are insulating fossil fuel generators from those risks.

At the very least, these interventions make it more difficult for states to determine which generators enter and exit the market. In addition, the Mystic bailout and other RMR contracts make it impossible for states to realize their generation preferences. Given these circumstances, it seems hard to see how this RMR agreement is consistent with Section 201(b) of the FPA. The problem, perhaps, is that state challenges to FERC interventions have focused on a specific FERC order that makes it more difficult for states to realize their resource preferences. Because FPA jurisdiction is often concurrent, so long as that individual intervention does not commandeer states’ authority over generation, it should be upheld.

Altogether, though, these interventions threaten to swallow state jurisdiction whole. The Mystic bailout requires Massachusetts ratepayers to support a generator despite the fact that the state was not convinced that the unit was necessary for reliability. The fact that FERC failed to permit a large offshore wind facility to participate in the ISO-NE capacity auction will force New England ratepayers to pay hundreds of millions to retain resources without determining whether other approaches might have resolved the problem more efficiently. In our view, a challenge to FERC’s general approach to reliability could show that FERC is interfering excessively with states’ authority over generation.

412 See Calpine Corp., 163 FERC ¶ 61,236 (June 29, 2018) (Glick, Comm'r, dissenting), slip op. at 5-6 (observing that the majority order never defines market “integrity”); ISO New England Inc., 162 FERC ¶ 61,205 (Mar. 9, 2018) (Glick, Comm'r, dissenting in part and concurring in part), slip op. at 4-5 (questioning the aim of “investor confidence”).

413 See 16 U.S.C. § 824e(a) (2018) (“Whenever the Commission . . . shall find that any rate, charge, or classification . . . is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate.”).

414 See Constellation Mystic Power, LLC, 165 FERC 61,267 (Dec. 20, 2018) (Glick, Comm'r, dissenting), slip op. at 2-3 (“I continue to believe that, had the Commission convened a process to examine fuel security in New England more holistically, the region might well have produced a solution that is more effective, less costly, and on far firmer legal footing.”).
VI. FINDING THE MISSING MONEY IN A HIGH-RENEWABLES GRID

Rather than revive utility rate regulation, FERC should encourage payment systems that preserve competition, support reliability, and accommodate state preferences for renewables. This Part first outlines general principles that would advance these goals. It then proposes specific policy changes to maintain competitive electricity markets in a future electric power grid.

A. Principles for Legal and Competitive Reserve Markets

Regulatory interventions aimed at securing resource adequacy are problematic because they (1) undermine the Federal Power Act’s federalist structure, (2) rely on administrative judgment—not competitive processes—to procure resource adequacy, and (3) counteract state renewable policies. The principles described in this Section would support efforts to procure sufficient reserves while respecting the FPA’s jurisdictional limits, retain competitive forces in electricity markets, and integrate state clean energy policies.

1. Reserve Requirements Do Not Trump the Rest of the FPA

While FERC and the grid operators should be able to create reserve requirements, they should not do so at the expense of other provisions of the FPA. Not only do states have authority over generation resources, but FERC is also statutorily required to ensure that rates are “just and reasonable” and not “unduly discriminatory.” FERC has to balance these numerous regulatory obligations. Reliability concerns do not give the Commission license to disregard these other statutory mandates.

Yet FERC seems to be using its authority over reliability to approve regulations that discriminate against renewables and that prevent states from exercising control over their resource mix. As discussed in Part IV, capacity market reforms and RMR contracts counteract state renewable policies and are not needed to support grid reliability. Rather than prevent undue discrimination in wholesale electricity markets, FERC’s decision to favor incumbent fossil fuel generators suggests that the Commission is itself contributing to discriminatory pricing practices in violation of Section 206 of the FPA. Giving states and LSEs a role in determining how to comply with FERC’s reserve requirements would better accommodate the FPA’s different jurisdictional and regulatory ambitions.

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416 Id. §§ 824d(a)-824e(a).
417 Cf. id. § 824e(a) (requiring FERC to adjust any “rate, charge, or classification” it determines is “unjust, unreasonable, unduly discriminatory or preferential”).
2. Competitive Processes—Not Bailouts—for Resource Procurement

Similarly, FERC should not use its authority over reliability to force LSEs to procure reserves in any particular way or bail out specific generators.\textsuperscript{418} Renewables do increase the need for capacity payments, but a centrally administered capacity market operates at cross-purposes with states’ ability to determine their own resource mixes. Capacity markets wrongly assume that sufficiently large reserve margins will secure all of the services needed to maintain reliability. When they fail to support flexible resources or other crucial generators, grid operators bail out the units deemed necessary for reliability. The result is a series of haphazard subsidies in which grid operators, with FERC’s blessing, prospectively identify critical resources and ensure that they operate. In this way, capacity markets increase the barriers to entry for renewables and counteract state clean energy policies. Rather than mandate the use of specific resources and impose barriers to entry and exit that protect incumbents even after they are no longer needed to support grid reliability, FERC and the grid operators should remove restraints on entry and exit. When a resource can provide the services consumers value, it should be able to compete to provide that service.

This principle has implications for both technical capacity market rules and bailouts of specific generators. There is no need for grid operators and FERC to stipulate that only resources that currently provide a service can be compensated for doing so. FERC should instead make sure that there is a competitive process in all ISOs and RTOs to retain the services consumers demand from the power grid. For example, capacity markets should be seasonal to better accommodate seasonal and intermittent renewables, battery performance requirements should be shortened so that batteries can be compensated when they provide electricity at peak hours, and capacity payments for intermittent resources should be discounted based on actual performance.\textsuperscript{419} More importantly, they should be voluntary so that LSEs can procure some—or all—of their capacity bilaterally when doing so is necessary to comply with other regulatory requirements.

The same principles apply to bailouts of fossil fuel generators perceived to be critical to grid reliability. Bailing out shareholders through RMR

\textsuperscript{418} In addition to the recent Mystic bailout, FERC has required grid operators to create a process for designating RMR contracts with critical generators. These contracts entitle generators to recoup their costs and making a profit by charging ratepayers—not by entering energy or capacity markets. \textit{See, e.g.}, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 1: PJM Interchange Energy Market § 6.1 (Feb. 18, 2012), https://www.pjm.com/directory/merged-tariffs/oa.pdf [https://perma.cc/NP89-EP42] (introducing the procedures that apply to “generation resource[s]” that have been designated necessary to run in order to “maintain the reliability of service in the PJM region”).

\textsuperscript{419} \textit{See supra} subsection IV.A.1.
agreements revives the problems that are traditionally associated with cost-of-service regulation. Generators such as Mystic have an incentive to inflate costs and overbuild capacity. Other resources cannot replace the incumbent even when it would provide superior services.

A competitive auction is a more efficient and effective way to retain critical units. Once a generator declares that it needs to retire, an auction would give competitors an opportunity to take over the critical resource. Alternatively, firms could submit proposals about alternative strategies that would maintain reliability even if the plant retired. Such a process recently played out in California when a natural gas peaking plant petitioned for cost recovery. Instead of immediately granting the petition, the state solicited proposals. This process demonstrated that coupling new solar with batteries would actually deliver the same level of reliability at lower cost.

This approach would have mitigated the problems that occurred when FERC bailed out the Mystic natural gas power plant. If Mystic determined that it genuinely needed additional revenues to continue to operate, an auction would have ensured that New England ratepayers received service from the entity that won the auction—whether that entity took over Mystic’s generators or submitted an alternative proposal that FERC and ISO-NE had not considered when they announced that Mystic had to be bailed out.

3. Accommodate State Preferences

Finally, FERC and the grid operators should integrate—not counteract—state programs to support zero- and low-carbon resources. Decisions by states or consumers to pay for specific characteristics such as backup capacity or carbon-free electricity should be welcomed by FERC. So long as there is a market for capacity, state policies will not force needed fossil fuel generators to retire. That is because the price for units that provide capacity needed by the grid will rise to support critical generating units. For years, FERC and grid operators have accommodated state subsidies. If a state is willing to shoulder some of the costs of a generating unit, there is no need for FERC or a grid operator to prevent it from doing so.

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420 See Julian Spector, PG&E Must Solicit Energy Storage and DERs to Replace 3 Existing Gas Plants, GREENTECH MEDIA (Jan. 15, 2018), https://www.greentechmedia.com/articles/read/pge-must-solicit-energy-storage-ders-to-replace-three-existing-gas-plants?gs=xMhsj3bh [https://perma.cc/B7P6-DB66] (discussing California’s "shakedown" process of awarding energy contracts which amounts to a choice between "giv[ing them] the lucrative deal or los[ing] the vital resources").

421 See Calpine Corp., 169 FERC ¶ 61,239, slip op. at 32-33 (Dec. 19, 2019) (expanding the definition of resources subject to the MOPR to include state-subsidized renewables).
B. A Three-Tranched Resource Procurement Requirement

To advance the principles outlined above, this Article proposes resource adequacy requirements to LSEs. This would allow LSEs to balance the imperatives of procuring a low-cost, reliable, and clean energy electric power supply. FERC should set performance standards governing the tranches with reference to state policies and allow LSEs to determine for themselves the most efficient way to comply with various state and federal energy regulations.

LSEs could “tranche” their portfolio. One tranche would consist of a clean energy tranche, another would be a flexibility tranche, and another a capacity tranche. The clean energy tranche would be based on aggregated state renewables and zero-emission mandates that affect particular markets. For example, if California requires that sixty percent of electricity come from zero-carbon sources by 2030, the clean energy tranche for the California market would require sufficient renewable capacity to meet the sixty-percent target. The flexibility tranche requirement would be based on a region’s calculated need for flexible resources, determined at least in part by the clean energy tranche requirement. Finally, the capacity tranche requirement would be set based on peak demand plus a reserve margin. The capacity tranche would resemble today’s capacity markets, but instead of a mandatory central auction, LSEs would have the option to participate in a central auction or to procure capacity for themselves. Furthermore, the capacity tranche would operate as a residual to the clean energy and flexibility tranches, rather than as the core of the capacity market.

LSEs would not be forced to buy a percentage of electricity from fossil fuel generators when doing so would prevent them from complying with state environmental laws. LSEs would be able to satisfy these requirements by building their own generators, contracting bilaterally, or transacting on a central market overseen by FERC or the grid operators. To ensure that LSEs do not secure excess capacity, regulators would allow the tranches to overlap. Since capacity refers to all of the reserves an LSE needs, the capacity tranche would actually encompass all of the electricity an LSE had procured, including electricity that the entity also used to satisfy the flexibility and clean energy tranches. LSEs would use the capacity tranche to show FERC and its grid operator that it had procured enough electricity to comply with

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422 Parts of this proposal already exist in California, which allows generators to charge for being available to supply electricity without awarding a handout to incumbent suppliers that do not need to receive a subsidy every time the market needs to signal that new generators should enter the market. See CAL. ISO, FINAL FLEXIBLE CAPACITY NEEDS ASSESSMENT FOR 2017, at 3-5 (2016), http://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf [https://perma.cc/Q2BU-36CL] (discussing California’s system of studying and allocating flexible capacity need).
its reserve requirement. An additional benefit is that LSEs would be able to incorporate price signals sent by states and consumers willing to pay more for certain resources. Because LSEs would be able to contract directly with generators, potential suppliers would compete for contracts. In this way, our proposal would preserve competition in electricity markets.

Another benefit of this proposal is that it would make it easier to retire uneconomic generators. As discussed in Section IV.B, the length of capacity market commitment periods causes retention of inefficient generators for years after they could retire. If LSEs procured capacity for themselves, they could pay inefficient generators to retire when less expensive alternatives became available. Old generators struggling to survive might prefer to be paid to retire than be forced to operate with low margins. The LSE would be in a position to encourage new generators to enter the market when it is economic for them to do so.

Optional capacity markets would resemble exchanges for long-term contracts and would thereby reduce the transaction costs associated with finding new load. Energy markets would become real-time flexibility markets used by grid operators and LSEs to balance load. Rather than compete for the favor of regulators, generators would compete to provide the services Americans expect from the power sector. There is no reason that all capacity should clear at the same rate when different generators provide different services depending on their ability to ramp up, curtail supply, ease transmission congestion, or support state renewable policies. Energy markets, in turn, would reward flexible generating units—the attribute that actually supports grid resilience. Rather than retain reliability through regulatory fiat, this structure would realize the goal of restructuring by relying on competitive processes to secure all of the services consumers demand from the power grid. It would do so, moreover, without bailing out fossil fuel generators.

CONCLUSION

It is somewhat ironic that FERC has resurrected utility rate regulation by claiming that aggressive regulatory interventions are needed to protect competition in the electric power industry. The Commission seems to be using the language of “investor confidence” and market “integrity” as a rhetorical device to justify a sweeping federal strategy to counteract state clean energy programs, prevent renewables from displacing traditional generators, and resurrect a system of administrative pricing in important wholesale markets.

This Article provides a sobering analysis of the technical and regulatory obstacles to reducing carbon emissions in the electricity sector. Hidden regulatory interventions designed to shore up grid reliability are being used
to counteract ambitious decarbonization proposals. Although there is no reason for FERC to bail out fossil fuel generators, FERC has nevertheless used its authority over grid reliability to shield incumbent fossil fuel generators from competitive forces. From an economic standpoint, these interventions make little sense. They revive rate regulation of generation along with all of the inefficiencies that plagued that system. From a legal standpoint, these interventions are inconsistent with the federalist vision embraced by the FPA.

Rather than revive rate regulation, this Article has argued that FERC should simplify reserve requirements, stop counteracting state clean energy programs, and support the development of competitive markets for capacity. FERC could—and should—secure the services needed to operate a clean and reliable power grid without shielding favored generators from competition.