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Accidents of Federalism: Ratemaking and Policy Innovation in Public Utility Law

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ABSTRACT

Decarbonizing the electric power sector will be central to any serious effort to fight climate change. Many observers have suggested that the congressional failure to enact a uniform system of electricity regulation could stifle the transition to a low-carbon electricity grid. This Article contends that the critique is overstated. In fact, innovation is occurring across different aspects of the electricity system and across different types of states in ways one would not expect to see under a single, national approach. As the Article demonstrates, this innovation stems in part from Congress's failure to enact a single, national approach to electricity regulation, which has given states the ability to choose whether and how to participate in restructured electricity markets. This ability to opt into or out of wholesale and retail competition has resulted in three regulatory models now operating across the country, combining different approaches to wholesale and retail regulation. Under each of these models, a number of state public utilities commissions (PUCs) are using their powers to set utility rates in surprisingly innovative ways and are targeting different aspects of the electricity system in a manner that will help transition to an electricity grid that is greener, less carbon-intensive, more efficient, and more distributed than the current system. The Article claims that the diversity of policy innovations occurring across these different models, and the system-wide benefits they are producing, are unexpected outcomes of the distinctive structure of federalism that continues to animate the U.S. system of electricity regulation and the limited reach of policies to promote competition in the sector. When combined with specific federal policy nudges and subsidies to encourage state experimentation in ratemaking, the three-model system is producing significant and underappreciated benefits as the United States confronts the challenges of decarbonizing the electricity grid. While the current system may not be ideal, it is the system we will likely be working with for some time to come. As a result, understanding the nature of these ratemaking experiments, and the innovations they enable, will be key to the successful implementation of EPA's Clean Power Plan or any other federal effort to cut greenhouse gas emissions from the power sector.

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INTRODUCTION

Any serious effort to reduce greenhouse gas (GHG) emissions in the United States will require a dramatic transformation of the nation's electric power system. The electricity sector currently accounts for nearly a third of U.S. GHG emissions, the largest single source in the economy.[1] A decarbonized electric power system is also critical to reducing emissions from transportation, the nation's second largest source of GHG emissions, given the need to replace much of the existing fleet with electric vehicles.[2] Put simply, decarbonizing the electric power sector is far and away the most important component of any effort to meet ambitious U.S. GHG reduction targets by 2050 and beyond.[3]

Transitioning to low-carbon electricity will require overhauling what has been called the most complex machine ever built.[4] We will need to see changes across the machine, from the sources of energy used to generate electricity, to the means of transmitting and distributing that electricity, to the way in which end users interact with the grid. Not only is the machine complex, but the regulatory system that governs it is multilayered, messy, complicated, and technical. Understanding and grappling with both the complexity of the machine and its regulatory overlay will not be easy.

Policymakers and legal academics have appropriately focused much of their attention to date on how the government can best reduce GHG emissions. Debates about whether to adopt a cap-and-trade system or a

1. *See* U.S. ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2012, at ES-23 (2014).
2. S*ee* MASS. INST. TECH., ELECTRIFICATION OF THE TRANSPORTATION SYSTEM 2, 19–25 (2010), https://mitei.mit.edu/system/files/electrification-transportation-system.pdf [http://perma.cc/VC3N-2MLM].
3. The Obama Administration has committed to reducing domestic emissions by 26–28 percent below 2005 levels by 2025 as part of a pathway to 80 percent reductions by 2050. *See United States Cover Note*, *INDC and Accompanying Information*, U.N. FRAMEWORK CONVENTION ON CLIMATE CHANGE (Mar. 31, 2015), http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf. At the heart of the U.S. commitment is the Clean Power Plan, designed to cut emissions from existing power plants by 32 percent by 2030. *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, at 64,665 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60).
4. PHILLIP F. SCHEWE, THE GRID: A JOURNEY THROUGH THE HEART OF OUR ELECTRIFIED WORLD 1 (2007) ("Taken in its entirety, the grid is a machine, the most complex machine ever made."); *see also* THOMAS P. HUGHES, NETWORKS OF POWER: ELECTRIFICATION IN WESTERN SOCIETY, 1880–1930, at 1 (1983).

tax[5] or whether the U.S. EPA has legal authority to use various sections of the Clean Air Act[6]—including Section 111(d), the basis for the Clean Power Plan regulations for existing power plants[7]—are important and difficult ones. So are questions about the role of various policy instruments to promote renewable energy, such as Renewable Portfolio Standards (RPSs) and tax credits.[8] But not enough attention has been given to the structure and practice of electricity regulation in the United States and the tools available under public utility law to promote decarbonization.[9]

Despite significant changes in the electricity sector over the past twenty years as the federal government has opened up wholesale electricity markets to competition and as some states have embraced retail competition, Public Utility Commissions (PUCs) and state public utility law more generally continue to play fundamental roles in determining basic features of our electricity system. In part, this is by design, but in part it is also by accident. Because the push to create competitive electricity markets never took complete hold across the country—a reflection of the commitment in the Federal Power Act[10] (FPA) to a strong state role in electricity regulation[11]—states have enjoyed considerable leeway in

5. *See generally* SHI-LING HSU, THE CASE FOR A CARBON TAX: GETTING PAST OUR HANG-UPS TO EFFECTIVE CLIMATE POLICY (2011); Gilbert E. Metcalf & David Weisbach, *The Design of a Carbon Tax*, 33 HARV. ENVTL. L. REV. 499 (2009).

6. 42 U.S.C. § 7401 (2012).

7. *See* 42 U.S.C. § 7411(d) (2012). *See generally* Robert R. Nordhaus & Ilan W. Gutherz, *Regulation of CO_2 Emissions From Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority*, 44 ENVTL. L. REP. 10366 (2014).

8. *See* MARK BOLINGER, LAWRENCE BERKELEY NAT'L LABORATORY, AN ANALYSIS OF THE COSTS, BENEFITS, AND IMPLICATIONS OF DIFFERENT APPROACHES TO CAPTURING THE VALUE OF RENEWABLE ENERGY TAX INCENTIVES 1–13 (2014) (evaluating various renewable energy tax credits and their implications for different technologies); Lincoln L. Davies, *Power Forward: The Argument for a National RPS*, 42 CONN. L. REV. 1339, 1339 (2010); David B. Spence, *The Political Barriers to a National RPS*, 42 CONN. L. REV. 1451, 1451 (2010) (discussing pros and cons of renewable portfolio standards).

9. For a thoughtful counterexample, *see* Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 U. ILL. L. REV. 1, 44–54 (2014) (describing innovative policymaking by the Midwest Independent System Operator and other ISOs in integrating wind and renewable energy and encouraging transmission line financing); Jim Rossi, *The Political Economy of Energy and Its Implications for Climate Change Legislation*, 84 TUL. L. REV. 379, 379–80 (2009) (arguing that understanding the electricity sector and the way it is regulated is crucial for designing effective climate policy).

10. 16 U.S.C. § 791 (2012).

11. *See* 16 U.S.C. § 824(a) (2012) (declaring that federal regulation of the sale and transmission of electricity shall "extend only to those matters which are not subject to regulation by the States"); 16 U.S.C. § 824(b)(1) (2012) (providing that the Commission "shall not have jurisdiction, except as specifically provided . . . 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, or over facilities for the transmission of electric energy consumed wholly by the transmitter.").

deciding whether they will participate in wholesale and retail electricity markets, continue with the traditional model of utility regulation, or pursue a mix of the two.[12] Although the goal of electricity restructuring was to fully deregulate the sector, the result has been messier, with three basic models of electricity regulation emerging across the country: a fully restructured model that combines competition at wholesale and retail levels; a traditional model that continues to employ the basic cost-of-service approach to regulating vertically integrated Investor Owned Utilities (IOUs); and a hybrid model that combines competitive wholesale markets with regulated retail service.[13] Notwithstanding the introduction of wholesale and retail competition in a number of states, PUCs retain important power in designing and setting electricity rates under each of these regulatory models. It is this ratemaking power across a diverse group of states—and the role it can and is playing in developing a greener, nimbler, more distributed grid—that is the focus of this Article.

Our focus on electricity ratemaking and its role in decarbonizing the grid has several aims. First, we argue that the need for innovative ratemaking is crucial to promoting technological innovation and deployment in the power sector.[14] As the traditional distribution system shifts from a one-way network that provides power to end users to a multi-directional grid where some users generate their own electricity and feed excess power back to the grid, individual actors and technologies are interacting with the system in new and dynamic ways. Still more change is occurring in response to the need for low- and zero-carbon generation, with policies aimed at producing more solar, wind, and nuclear power, and even new coal generation from plants equipped with the ability to capture and store carbon emissions. Making this greener grid a reality will require substantial new investments across all aspects of the machine. We will need innovation and investment in everything from generation to transmission to local distribution to end use, which will in turn require new rate designs to accommodate cost recovery, promote and reward the proliferation of different energy resources and services, and encourage consumer behavior to take advantage of technology that

12. For an excellent overview of the move to competitive markets in the United States and Europe, see David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 776–87 (2008).

13. *See* William Boyd, *Public Utility and the Low-Carbon Future*, 61 UCLA L. REV. 1614, 1630–31, 1661–74 (2014) (discussing electricity restructuring and the resulting three models of regulation).

14. We use innovation as a general term in this Article to refer not only to novel approaches to policy and ratemaking, which we sometimes refer to as "experimentation," but also to new technologies and, particularly, the testing and deployment of technologies and programs to promote low-carbon electricity. Innovative ratemaking, in this respect, serves as a critical tool to promote technological innovations directed at decarbonizing the power sector.

creates a more dynamic and more efficient grid. Given their jurisdiction over decisions about generation, the use of local distribution systems, and the design of retail rates, PUCs will be at the center of these changes.

Second, we demonstrate that the United States is, in fact, seeing interesting examples of policy innovation and the use of ratemaking powers in each of the three models of electricity regulation (traditional, restructured, and hybrid) that have emerged out of electricity restructuring. To be sure, there are numerous states that are not innovating, and some that are innovating in ways that are inhibiting rather than facilitating decarbonization. But our focus here is on states that are pushing forward with potentially important experiments for the broader effort to decarbonize the grid. To that end, we describe and analyze four areas of ratemaking that are driving investments and changing behavior in ways that could be crucial to decarbonizing the grid: 1) promoting low- or zero-carbon baseload generation; 2) modernizing the grid; 3) promoting distributed energy resources; and 4) using time-variant pricing to encourage more efficient customer behavior. In examining each of these, we find that the nature of the policy experiments and the use of ratemaking appear to differ, at least in part, depending on the particular model of electricity regulation. In states operating under the traditional model, which still retain the most regulatory authority over the development and funding of large-scale generation sources, we see PUCs using their ratemaking powers to promote the development of coal-fired power plants with carbon capture and sequestration and nuclear power plants. In states operating under a restructured or hybrid model, by contrast, we see utility commissions focusing more heavily on the distribution side of the grid, which is the portion of the grid that delivers electricity directly to customers. Some states are experimenting with performance-based rates to encourage utilities to make large-scale investments in distribution system infrastructure while others are allowing distribution utilities to recover the costs of these investments in advance through ex ante prudency determinations and accelerated cost recovery. These investments are crucial to integrating distributed generation into the grid, optimizing performance, and using rate design to promote more efficient consumer behavior. These states are also using their ratemaking powers to encourage distributed generation by imposing storage mandates, developing infrastructure to incorporate large numbers of electric vehicles into the system, and compensating customers for providing excess generation from rooftop solar and other local generation sources, while simultaneously devising policies to eliminate cross-subsidies from traditional customers who continue to receive electricity from utilities. And in hybrid and restructured states we see PUCs developing more robust time-variant pricing policies, including opt-out rather than opt-in designs for residential programs, to align customer pricing with the actual cost of electricity generation and to encourage more efficient energy use.

Third, we suggest that this diversity of experimentation is in part the result of what we call "accidents of federalism."[15] The three models of U.S. electricity regulation can hardly be considered the rational result of intentionally designed federal policy. To the contrary, they might even be viewed as the result of policy *failure* as the Federal Energy Regulatory Commission (FERC)'s vision of fully restructured wholesale energy markets (endorsed in broad terms by the U.S. Congress) never took complete hold and as the move to introduce competition into retail electricity faltered after the California energy crisis. Numerous commentators decry the current system for its lack of national coherence, and more than a few have called for a larger federal role in electricity regulation.[16] Nevertheless, despite the messy and complex federal system, or maybe because of it, some states and PUCs are deploying new and innovative approaches to ratemaking as a means of promoting investment in low-carbon technologies and practices across the sector. Taken as a whole, we argue that this mix of innovative ratemaking, and the range of technological innovations that it enables, is different than the innovation that might emerge from a more uniform system. As we demonstrate, traditional states that still regulate the generation side of the grid through cost-of-service regulation have different powers and

15. In using this term, we recognize that any commitment to federalism, and certainly the dual model of state and national authority in the electricity sector, is going to produce unanticipated results. That is, we recognize that contingency is embedded in the deep structure of American federalism. While our use of the term "accidents" is intended in part as recognition of that contingency, it also seeks to capture the unintended outcome of the incomplete national effort to restructure electricity markets. As discussed in Part I *infra*, in the wake of the failure of restructuring to take complete hold across the country, the Federal Power Act (FPA)'s commitment to federalism has led to the diversity of policy innovation now seen across the three models of electricity regulation. Put another way, out of the interaction between the structure of federalism at the heart of the FPA (left largely undisturbed by the U.S. Congress for the last 80 years) and the partially realized commitment of federal policy (from both the Federal Energy Regulatory Commission (FERC) and Congress) to push for restructuring across the country, has come the unintended or "accidental" result of three models of electricity regulation that are together producing a diversity of policy innovations in the electricity sector.

16. *See, e.g.*, Joel B. Eisen, *Smart Regulation and Federalism for the Smart Grid*, 37 HARV. ENVTL. L. REV. 1, 20–21 (2013) (describing federal-state tensions in utility law); Jody Freeman & David B. Spence, *Old Statutes, New Problems*, 163 U. PA. L. REV. 1, 5 (2014) (suggesting that "dramatic technological, economic, and social changes [in the electricity sector] . . . would seem to demand a legislative response"); Osofsky & Wiseman, *supra* note 9, at 1 (describing the complexity of energy regulation as "problematic" and proposing new models of regulation for addressing such complexity); Hari M. Osofsky & Hannah J. Wiseman, *Dynamic Energy Federalism*, 72 MD. L. REV. 773, 827–35 (2013) (critiquing system of energy governance for providing inadequate authority to principal actors to address transitioning markets and for excessive fragmentation in assignment of regulatory authority).

are innovating in different ways than states in fully restructured markets that have largely residual power over the distribution side. Thus an important result of the failure to establish a uniform national system of electricity regulation is the production of a diverse set of regulatory experiments that would likely not have arisen otherwise. We should be clear that our claim is not that the current system is superior to an alternative system with a more centralized approach to electricity regulation (or decentralized through markets). Instead, our argument is that innovative use of ratemaking powers is occurring in the current system, that such innovation is different from what would have occurred had the push for wholesale and retail competition taken hold across the whole country, and that legal scholars have largely ignored these developments.

The innovations in ratemaking we identify are not, however, only the unintentional byproduct of a lack of a uniform national policy. Instead, we also show that through a variety of mechanisms, the federal government has used more intentional policy nudges and subsidies to push states to innovate. These include statutory changes, FERC rulemakings, and federal spending, each of which has helped encourage states to use their ratemaking powers to promote low-carbon technologies and practices by reducing some of the risk of these experiments. This more directed federal policy, combined with the three-model system, is helping to drive low-carbon investments across the whole sector in a manner that might not occur under a more uniform system. We also suggest, however, that federal policy could be used in a more systematic way to encourage and learn from the kinds of policy experiments that are underway in the three different regulatory models.

One additional aim of this Article, then, is to demonstrate the ways in which our account of ratemaking speaks to ongoing debates about federalism. Two debates seem especially pertinent. One asks whether federalism promotes or produces too little policy innovation. Although standard claims about the virtues of federalism focus to a large extent on states as innovators—and PUCs can rightly claim to be the original Brandeisian laboratories of democracy[17]—an opposing theory suggests that federalism produces too little innovation.[18] The basic

17. New State Ice Co. v. Liebmann, 285 U.S. 262, 311 (1932) (Brandeis, J., dissenting) (characterizing states as laboratories in case involving Oklahoma effort to extend a scheme of quasi-public utility regulation to the manufacture and sale of ice); *see also* Boyd, *supra* note 13, at 1645–47, 1704–08 (discussing earlier "experimentalist" views of public utility and the importance of recovering PUCs' capacity for policy experimentation and innovation).

18. *See, e.g.*, Susan Rose-Ackerman, *Risk Taking and Reelection: Does Federalism Promote Innovation?*, 9 J. LEGAL STUD. 593, 594 (1980) (arguing that state politicians are risk averse and unlikely to engage in experimentation); Edward L. Rubin & Malcolm Feeley, *Federalism: Some Notes on a National Neurosis*, 41 UCLA L. REV. 903, 909 (1994) ("[F]ederalism . . . does not encourage

argument is that states will free ride on the innovative efforts of other states because any individual state bears all the policy risk for innovations that fail and gains only some of the benefits from policy successes since other states can wait and adopt only those policies that succeed. If states, in fact, reason in this way, too little policy innovation may be occurring. Without resolving this theoretical debate, our account of innovation and electricity ratemaking suggests that the federal government—acting largely through policy nudges and subsidies—may be reducing the risk of state policy innovation failure and hence helping to spur more experimentation in electricity ratemaking across the three models than would otherwise occur.

Our account also allies us with an emerging school of federalism that suggests that structures of federalism, including the devolution to states of policymaking authority, can be deployed not only to support traditional values like local control and policy diversity but also to promote national values and policies.[19] We think the system of electricity regulation that has emerged in the wake of restructuring—one that combines considerable state autonomy to choose whether and how to participate in wholesale and retail electricity markets with federal policies and subsidies to promote low- and zero-carbon electricity production across the grid—effectively illustrates this "federalism as nationalism." Through a largely federal structure that has led to regulatory diversity, states operating in quite different political and economic circumstances are using their ratemaking powers to construct a lower-carbon, greener grid in alignment with

experimentation."); Brian Galle & Joseph Leahy, *Laboratories of Democracy? Policy Innovation in Decentralized Governments*, 58 EMORY L.J. 1333, 1339 (2009) (evaluating three decades of scholarship on Rose-Ackerman's hypothesis and concluding that "there is at least a large grain of truth to [her] assessment" and that state and local governments "are unlikely to innovate at the optimal social level, or in a way that captures the true benefits of experimentation"). *But see* DAVID L. SHAPIRO, FEDERALISM: A DIALOGUE 85–88 (1995) (arguing that federalism has produced innovation in numerous policy areas).

19. Many scholars have recognized the broad virtues of a system of federalism that is far more dynamic, more complex, and more interactive than sometimes characterized in the literature. *See, e.g.*, William W. Buzbee, *Contextual Environmental Federalism*, 14 N.Y.U. ENVTL. L.J. 108 (2005) (arguing that multiple layers of government produce more dynamic and more protective environmental outcomes); ROBERT A. SCHAPIRO, POLYPHONIC FEDERALISM: TOWARD THE PROTECTION OF FUNDAMENTAL RIGHTS (2009) (highlighting the ways in which federalism has become more, not less important in an era of stronger national government); Ann E. Carlson, *Iterative Federalism and Climate Change*, 103 NW. U. L. REV 1097, 1100 (2009) (examining the interaction between state and federal law in producing innovative policy outcomes). Heather Gerken has argued that these and other federalism scholars recognize the ways in which federalism is not merely a system that promotes parochial state views, but can instead promote national policies and politics. *See* Heather K. Gerken, *Federalism as the New Nationalism: An Overview*, 123 YALE L.J. 1889, 1892 (2014) ("It is possible to imagine federalism integrating rather than dividing the national polity."); *see also* Abbe R. Gluck, *Our [National] Federalism*, 123 YALE L.J 1996, 1997 (2014) (describing the ways in which Congress uses states to achieve national ends).

national goals to develop cleaner generation, promote diversity of supply, transition to a nimbler and more efficient grid, and even, at least at the executive branch level, to reduce GHG emissions[20]—all with a push from the federal government to guide them.

Our final purpose in focusing on innovative PUC ratemaking is simply to highlight an under-examined policy tool that states across the country are using to encourage and, importantly, to pay for some of the large-scale innovations that will be necessary to decarbonize the electricity sector. Governments use various tools to encourage innovation all the time, from traditional regulation to taxation to direct subsidy to the protection of intellectual property. All of these tools will be (and to some degree already are) important in the effort to decarbonize. Each of these tools raises questions about efficiency, distributional consequences, and efficacy. Ratemaking presents another tool to encourage, de-risk, and socialize the costs of large-scale innovations in electricity infrastructure. We tend not to think of ratemaking in this way, yet it raises the same questions about efficacy, distributional effects, and efficiency. Our aim is to bring more attention to ratemaking and its role in promoting innovation.

The Article proceeds as follows. Part I provides background on the U.S. electric power system and the regulatory frameworks that govern it, with particular attention to the role of PUCs. It has three objectives: (1) to describe briefly the physical nature of the electric power system and the challenges this poses for regulation; (2) to explain the traditional model of electricity regulation and the jurisdictional split between federal and state law; and (3) to establish the main features of the three different models of electricity regulation in operation today and the continuing relevance of rate design in each. Part II analyzes four specific and ongoing areas in which states and PUCs are using their ratemaking powers to promote various aspects of a low-carbon electricity system: advanced cost recovery for low-carbon baseload generation, grid modernization, distributed energy resources, and time-variant pricing. Part III then elaborates on broader lessons from these four cases, with specific attention to the role of PUCs and public utility law in driving clean energy innovation through ratemaking. It argues that the diversity of approaches to electricity regulation in our federal system has generated innovation across all three models of regulation and across all aspects

20. For an explanation of why states are pushing for cleaner energy, see BARRY G. RABE, PEW CTR. ON GLOBAL CLIMATE CHANGE, RACE TO THE TOP: THE EXPANDING ROLE OF U.S. STATE RENEWABLE PORTFOLIO STANDARDS iii (2006). For the President's rationale for clean energy investments, see *Promoting Clean, Renewable Energy: Investments in Wind and Solar*, WHITE HOUSE, https://www.whitehouse.gov/recovery/innovations/clean-renewable-energy [https://perma.cc/HF4E-HMJK] (last visited Mar. 20, 2016).

of the grid over which PUCs have jurisdiction. Part III also offers provisional explanations for why some regulatory innovations appear to come out of traditional cost-of-service states whereas others emerge from hybrid and restructured states and suggests reasons why some state PUCs lead while others lag behind. Finally, Part III intervenes in contemporary debates about federalism, turning first to questions about the role of federalism in spurring or hindering policy experimentation and next to debates about whether structures of federalism can be used to push national aims. We conclude by suggesting that the current moment of innovation in electricity ratemaking represents a realization in some respects of the experimentalist impulse that animated the establishment of PUCs in the early twentieth century.

I. THE U.S. ELECTRICITY SYSTEM AND REGULATORY JURISDICTION

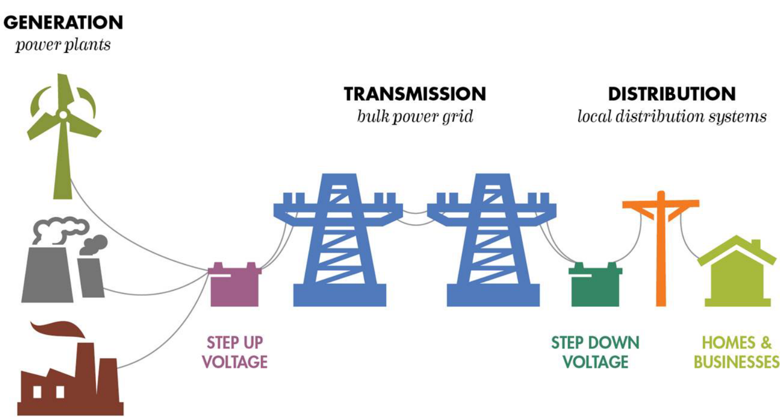
The U.S. electric power system has been described as the most complex machine ever built.[21] Organized into three major grids, or interconnects, (Eastern, Western, and Texas),[22] it joins a diverse array of generation assets with high-voltage transmission lines, local distribution systems, and increasingly active demand-side and distributed resources to deliver a highly reliable service to millions of households and businesses in a manner that must precisely balance generation (supply) and load (demand) in real-time.

Roughly speaking, the system can be divided into three major components: (1) generation, (2) transmission, and (3) distribution (see Figure 1 below). Generation converts primary energy (fossil hydrocarbons such as coal or natural gas, nuclear, wind, solar, hydro, and other renewable sources) into electricity.[23] Generators must then step up the voltage of their electricity for it to be transmitted long distances over high voltage power lines. This system of high-voltage transmission lines is used to move large amounts of power across the three major grids in the United States and is sometimes known as the bulk power grid.[24] At the

21. *See* HUGHES, *supra* note 4; MASS. INST. TECH., THE FUTURE OF THE ELECTRIC GRID: AN INTERDISCIPLINARY MIT STUDY 1 (2011), http://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf; SCHEWE, *supra* note 4; S. Massoud Amin, *Securing the Electricity Grid*, 40 BRIDGE 13, 14 (2010).
22. *See* MASS. INST. TECH., *supra* note 21, at 3.
23. Electricity is, in this sense, a secondary form of energy or what is sometimes referred to as an "energy carrier." *See* ELECTRIC POWER SYSTEMS i (Michael Crappe ed., 2008) ("Electricity is an energy carrier . . . .").
24. *See* Massoud Amin & John Stringer, *The Electric Power Grid: Today and Tomorrow*, 33 MRS BULL. 399, 400 (2008), http://massoud-amin.umn.edu/publications/The_Grid_Amin_Stringer.pdf (describing generation and high voltage transmission segments of U.S. electric power

other end of the transmission system, the electricity is then stepped down to lower voltage and distributed, via local distribution systems, to electricity consumers.[25] These local systems have historically transmitted power in one direction for end use in homes and businesses. It is this component of the system, however, that is changing most dramatically today as electricity consumers become active participants in the system through increased demand response, distributed generation, and storage.

FIGURE 1. MAJOR COMPONENTS OF A MODERN ELECTRIC POWER SYSTEM



Viewed as a whole, the electric power system is a complex, highly interdependent machine that operates on multiple time scales, ranging from milliseconds to years.[26] Because electricity cannot be stored on any significant scale and cannot be directed (as in the case of classic switched networks), and because generation and load must be precisely balanced in real time, sophisticated systems operation capabilities are necessary to ensure continuous delivery of reliable

grid); *see also* B.M. WEEDY ET AL., ELECTRIC POWER SYSTEMS 443–72 (5th ed. 2012) (describing basic components of electric power systems).

25. Amin & Stringer, *supra* note 24, at 400 (describing local distribution segment of U.S. power grid).

26. *See* ALEXANDRA VON MEIER, ELECTRIC POWER SYSTEMS: A CONCEPTUAL INTRODUCTION 260–68 (2006).

electric service.[27] The electric power industry has been described, in this respect, as the ultimate just-in-time system.[28]

A. The Traditional Regulatory Framework

These distinctive features of the electric power system create challenges for regulation and have informed the regulatory frameworks governing electricity over the last century. During the late nineteenth and early twentieth centuries, when electricity was generated in small power plants located close to demand, there was little need for state or federal regulation.[29] As the system grew, made possible in part by the use of alternating current and by increasing economies of scale in power generation, the need for regulation became more apparent, particularly in the wake of conflicts between electric utilities and municipal governments.[30] Utilities and their advocates pushed for state regulation by independent commissions as a way of avoiding logrolling in state legislatures and corruption in municipal governments.[31] Such regulation, it was hoped, would provide much-needed stability with respect to cost recovery and protection from wasteful competition.[32]

At the heart of this model was the independent public utility commission or PUC. Given the complexities of electricity and the need for continuous supervision

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27. For a good overview of the distinctive features of electric power systems and their implications for the current grid, *see* Brief for Federal Energy Regulatory Comm'n as Amicus Curiae Supporting Respondents at 2, 6–9, New York v. FERC, 535 U.S. 1 (2002) (No. 00-568).

28. *See* Paul L. Joskow, *Creating a Smarter U.S. Electricity Grid*, 26 J. ECON. PERSP. 29, 33 (2012).

29. *See* PAUL J. GARFIELD & WALLACE F. LOVEJOY, PUBLIC UTILITY ECONOMICS 28 (1964) ("From the late nineteenth century to about 1920, public utilities were regulated principally by local governments through franchise contracts."); MARTIN G. GLAESER, PUBLIC UTILITIES IN AMERICAN CAPITALISM 54–55 (1957) (discussing development of small, urban central station electricity using direct current for city lighting during the late nineteenth and early twentieth centuries); RICHARD F. HIRSH, POWER LOSS 12 (2002) (discussing spatial limits of direct current systems).

30. Alternating current allowed for higher voltage transmission across longer distances. *See* HIRSH, *supra* note 29, at 12–14 (discussing development of alternating current and use of steam turbines to capture economies of scale in power generation in the early twentieth century).

31. *See* Mansel Griffiths Blackford, *Businessmen and the Regulation of Railroads and Public Utilities in California During the Progressive Era*, 44 BUS. HIST. REV. 307, 313 (1970) (noting that "the public utility companies, especially the larger ones, were in the vanguard of those clamoring for . . . passage" of the California Public Utilities Act); Robert L. Bradley, Jr., *The Origins and Development of Electric Power Regulation*, *in* THE END OF A NATURAL MONOPOLY: DEREGULATION AND COMPETITION IN THE ELECTRIC POWER INDUSTRY 43, 46–61 (Peter Z. Grossman & Daniel H. Cole eds., 2003) (discussing the municipalization movement at the turn of the century and the move to regulation by state commissions); Forrest McDonald, *Samuel Insull and the Movement for State Utility Regulatory Commissions*, 32 BUS. HIST. REV. 241, 247–51 (1958).

32. *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, 1053 (2002).

of utilities, regulation by an independent commission staffed with experts and insulated from politics was viewed as superior to regulation by municipal governments or by the legislature.[33]

Between 1907 and 1930, every state but Delaware enacted public utility legislation that charged some type of administrative entity with responsibility for regulating public utilities such as water, gas, and electricity.[34] These were quintessential Progressive-era laws, built on principles of scientific management and regulation by experts.[35] Statutory mandates were typically broad and open-ended, founded on the goal of ensuring that rates were just, reasonable, and nondiscriminatory in order to strike the appropriate balance between ratepayers and investors.[36] These mandates remain at the heart of PUC powers and afford commissions significant discretion in exercising their ratemaking powers.[37]

As electric utilities expanded in the early twentieth century, interstate transfers of power became more common, but the U.S. Supreme Court prohibited states from regulating such transfers in 1927, creating a gap in the regulatory scheme.[38] In 1935, Congress responded with new legislation that gave the Federal Power Commission (FPC), predecessor of the Federal Energy Regulatory Commission (FERC), jurisdiction over rates for wholesale sales of electricity in interstate commerce and transmission of electricity in interstate commerce.[39]

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33. *See* MARTIN G. GLAESER, OUTLINES OF PUBLIC UTILITY ECONOMICS 251 (1927) (discussing advantages of independent, expert commissions); John R. Commons, *How Wisconsin Regulates Her Public Utilities*, 42 AM. REV. REVIEWS 215, 215 (1910).
34. *See* GARFIELD & LOVEJOY, *supra* note 29, at 32–33; William E. Mosher, *A Quarter-Century of Regulation by State Commissions*, 14 PROC. ACAD. POL. SCI. 35, 36–37 (1930).
35. *See, e.g.*, FINLA G. CRAWFORD ET AL., ELECTRICAL UTILITIES: THE CRISIS IN PUBLIC CONTROL 35 (William E. Mosher ed., 1929).
36. *See, e.g.*, Eugene A. Gilmore, *The Wisconsin Public Utilities Act*, 19 GREEN BAG 517, 517–18 (1907).
37. John Commons drafted Wisconsin's statute and viewed public utility as one of the core concerns of institutional economics. *See, e.g.*, JOHN R. COMMONS, LEGAL FOUNDATIONS OF CAPITALISM 327–29 (1924) (discussing broad concept of public utility, its relation to "the public," and its application to particular types of businesses); *see also* Malcolm Rutherford, *Understanding Institutional Economics: 1918–1929*, 22 J. HIST. ECON. THOUGHT 277, 299 (2000) ("Public utilities, including issues relating to the valuation of utility property and the proper basis for rate regulation, were major areas of institutionalist research.").
38. *See* Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).
39. United States v. Pub. Utils. Comm'n, 345 U.S. 295, 307–08 (1953) ("Part II [of the Federal Power Act] was intended to 'fill the gap' . . . left by *Attleboro* in utility regulation."); Conn. Light & Power Co. v. Fed. Power Comm'n, 324 U.S. 515, 525 (1945) ("The new title II of the [Federal Power Act] is designed to secure coordination on a regional scale of the Nation's power resources and to fill the gap in the present State regulation of electric utilities." (quoting Commissioner Seavey of the Federal Power Commission)). *But see* New York v. FERC, 535 U.S. 1, 20–21 (2002) (arguing that the FPA did more than merely close the gap but expanded federal jurisdiction to include transmission and some interstate wholesale sales over which states already had jurisdiction).

Intended primarily as gap filling, the newly enacted Part II of the FPA expressly reserved to the states jurisdiction over the planning and siting of generation infrastructure and ratemaking for retail sales of electricity and use of local distribution systems.[40] The overall intent was to clearly demarcate the line between state and federal jurisdiction, leaving states whole in their efforts to regulate electricity within their domain and to complement their regulatory authority with federal oversight of the interstate dimensions of the sector.[41]

In practice, this jurisdictional split, which persists largely unchanged to the present day, meant that for much of the twentieth century, federal regulation of electricity was quite limited. Because the electricity sector was dominated by vertically integrated investor owned utilities (IOUs) that owned generation, transmission, and distribution and provided a bundled service to retail customers, state PUCs carried the bulk of the regulatory responsibilities.[42] In setting retail rates, they sought to capture all of the costs associated with these different activities. The FPC played a modest role in regulating occasional inter-utility sales of power and, more importantly, sales by IOUs to municipal utilities and rural electric co-ops.[43] Use (or attempted use) of the IOU's transmission systems by third parties was very limited.[44] Over time, as we will see, the federal role in regulating wholesale power transactions increased considerably with the move to

40. *See* 16 U.S.C. § 824(a) (2012) (declaring that federal regulation of the sale and transmission of electricity shall "extend only to those matters which are not subject to regulation by the States"); *id.* § 824(b)(1) (providing that the Commission "shall not have jurisdiction, except as specifically provided . . . 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, or over facilities for the transmission of electric energy consumed wholly by the transmitter").

41. *See, e.g.*, Fed. Power Comm'n v. S. Cal. Edison Co., 376 U.S. 205, 215 (1964) ("Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction . . . .").

42. *See* Paul L. Joskow, *Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector*, 11 J. ECON. PERSP. 119, 121 (1997) ("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. That is, the typical utility is vertically integrated into four primary electricity supply functions: generation, transmission, distribution and retailing."); Paul L. Joskow, *Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry*, BROOKINGS PAPERS ON ECON. ACTIVITY: MICROECONOMICS 125, 134 (1989) [hereinafter Joskow, *Regulatory Failure*] (noting that because utility assets have historically been owned by the same corporate entity providing a bundled retail service, "most of a utility's costs are subject to state rather than federal regulatory authority").

43. Joskow, *Regulatory Failure*, *supra* note 42, at 134 (noting limited role of federal regulation of electricity prior to restructuring).

44. *See, e.g.*, Otter Tail Power Co. v. United States, 410 U.S. 366, 371 (1973) (discussing refusal by IOU to allow use of its transmission system to "wheel" power from Bureau of Reclamation hydroelectric facilities and electric cooperatives to municipal power systems). Because the Federal Power Commission had no authority under the Federal Power Act to order the wheeling, the Court affirmed the district court's decision to order wheeling as a remedy under the antitrust laws. *Id.* at 380–82.

competitive wholesale power markets. But state authority to choose how to regulate the electricity sector has nevertheless remained strong.[45]

B. The Structure and Practice of State Public Utility Regulation

From the outset, most PUCs were (and are) composed of three members (though some have had as many as seven and others as few as one).[46] Commissioners have typically been appointed by the governor, often according to specific requirements for split party affiliations, although a substantial minority of states provide for direct election.[47] Most commissioners in most states serve multi-year terms (six-year terms being the most common), with wide variation in staffing and budgeting.[48] Some PUCs depend on annual appropriations while others receive their funding from fees imposed on regulated utilities.[49] In leading states such as New York and California, commissions have been well staffed and relatively well compensated since their inception.[50] In other states, PUCs have been woefully understaffed and underfunded.[51]

Typical duties in the early years included establishing rules for accounting and valuation of utility assets, adjudicating rate cases, making prudency determinations for specific investments, investigating specific issues or companies, and

45. For a compelling argument that recent U.S. Supreme Court decisions interpreting the reach of both the Federal Power Act and the Natural Gas Act are shifting from the previous model of dual sovereignty to one of concurrent jurisdiction, see Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEXAS L. REV. (forthcoming 2016) (manuscript at 7–8), http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2733731.
46. *See* GARFIELD & LOVEJOY, *supra* note 29, at 262 (reporting numbers of commissioners ranging from one to seven and noting that the majority of state commissions had three commissioners). For the current status of state PUCs, including numbers of commissioners and staff, see *Regulatory Commissions*, NAT'L ASS'N REG. UTIL. COMM'RS, http://www.naruc.org/about-naruc/regulatory-commissions/ [https://perma.cc/G6PL-95MT] (last visited Mar. 20, 2016). California currently has five commissioners and New York currently has four.
47. GARFIELD & LOVEJOY, *supra* note 29, at 262 ("The selection by commissioners in most states is by gubernatorial appointment.").
48. *See id.* at 262–63 (discussing variation in commissioner terms and differences in budgeting and staffing).
49. *Id.* at 264–65 (discussing different approaches to financing commissions).
50. In 1947, for example, the total amount appropriated to forty-eight state utility commissions was $15.5 million, almost half of which ($7 million) went to just four commissions (New York, California, Pennsylvania, and Illinois). *See* John W. Ashley, *A Suggestion for Improving Public Utility Regulation*, 36 LAND ECON. 158, 158 (1960).
51. GARFIELD & LOVEJOY, *supra* note 29, at 263–65 (discussing differences in budget and staffing among state commissions); HIRSH, *supra* note 29, at 44 ("Inadequately equipped commissions remained the rule for decades. As late as 1967, only five state regulatory bodies employed two economists each, and forty-four bodies had no formal ability to perform economic analysis on an in-house basis."). These differences have persisted to the present. California, for example, currently has 940 staff members while Utah has just fifteen. *See Regulatory Commissions*, *supra* note 46.

enforcing orders.[52] PUCs were expressly conceived as "instruments of blended power" and provided some of the earliest test cases for emerging doctrines of administrative law.[53] In general, and notwithstanding a long and costly detour into constitutional review of ratemaking methodology precipitated by the Supreme Court's fair value rule in *Smyth v. Ames*, courts have generally been quite deferential to PUCs.[54] Most courts in most states accord PUCs significant deference when reviewing their actions.[55] PUCs whose powers stem from the state constitution may receive even greater deference.[56]

Given their broad statutory mandates and relative novelty as a governmental form, PUCs were viewed early on in "experimentalist" terms. Progressive-era lawyers and legal scholars, early institutional economists, and several prominent legal realists saw public utility regulation as an open-ended experiment with the potential to carve out a third way between outright public ownership and laissez-faire capitalism. Ratemaking was viewed as the core of this experimental potential.[57]

52. *See* GLAESER, *supra* note 33, at 233–62 (discussing typical duties and procedures of state commissions in the early twentieth century).

53. James O. Freedman, *Crisis and Legitimacy in the Administrative Process*, 27 STAN. L. REV. 1041, 1048 (1975) (describing PUCs as "instruments of blended power[]"); *see also* DANIEL R. ERNST, TOCQUEVILLE'S NIGHTMARE: THE ADMINISTRATIVE STATE EMERGES IN AMERICA, 1900–1940, at 33–50, 82 (2014) (discussing early development of administrative law principles and procedures in the context of PUC rate determinations).

54. Smyth v. Ames, 171 U.S. 361 (1898); *see also* Boyd, *supra* note 13 at 1644–45 (recounting history). Since the Supreme Court's 1944 decision in *Federal Power Commission v. Hope Natural Gas Co.*, the courts have no longer policed the methodology of ratemaking, leaving the details of the exercise to federal and state regulators as long as the end result satisfies the just and reasonable standard. *See* Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.").

55. *See, e.g.*, COLO. REV. STAT. § 40-6-115 (2013) (establishing limited standard of review); OR. REV. STAT. § 756.610 (2013) (describing Oregon's limited standard of review); PG&E Corp. v. Pub. Utils. Comm'n, 118 Cal. App. 4th 1181, 1194–97 (2004) (explaining deferential standard of review); Miss. Pub. Serv. Comm'n v. Miss. Power Co., 337 So. 2d 936, 939 (1976) (describing Mississippi's limited standard of review).

56. *See, e.g.*, Boris H. Lakusta, *Operations in an Agency Not Subject to the APA: Public Utilities Commission*, 44 CAL. L. REV. 218, 218 (1956) ("Through constitution and statute the California Public Utilities Commission enjoys an extraordinary sweep of substantive powers. . . . This sweep of powers derives particular strength from the 1911 constitutional amendments which have enabled the Commission to function unfettered by the doctrine of the separation of powers and the theories about unwarranted delegation of legislative or judicial power which so long plagued federal administrative agencies under former interpretations of the Federal Constitution and which continue to affect California agencies born under a less generous star." (footnotes omitted)). Lakusta was senior counsel at the California Public Utilities Commission at the time he published this article.

57. *See, e.g.*, Commons, *supra* note 33, at 223 (noting that Wisconsin's public utility law was designed to be "elastic enough to offer the opportunity for ingenuity and experiments that may combine the

For most of the twentieth century, the chief responsibility of PUCs was to establish rates for the services provided by IOUs. Under the typical approach, which remains dominant in traditional states, IOUs received long-term monopoly franchises in return for a commitment to provide reliable electricity to all customers within a defined service area at rates, terms, and conditions set by the commission.[58] Retail rates were established through trial-type "rate case" procedures based on cost of service.[59] Typically, the utility would initiate the rate case, presenting evidence of capital invested in generation, transmission, and distribution assets (known collectively as the rate base), a rate of return sufficient to cover the cost of financing investments in those assets, and estimates of expenses for depreciation, taxes, operations and maintenance.[60] These elements provided the basis for determining an overall revenue requirement—that is, the amount of revenue needed for the utility to recover its costs and continue as a going concern.[61] PUC staff and various interveners would respond to the utility's proposal, leaving the commission to evaluate the evidence and decide what rates to allow. Investments in rate base have typically been evaluated under the "prudent investment" standard, and in most states PUCs have only allowed assets to be included in rate base if they are "used and useful."[62] This basic approach was the core of the

principle of State regulation with that of private enterprise"); Robert L. Hale, *The "Physical Value" Fallacy in Rate Cases*, 30 YALE L.J. 710, 717 (1921) (characterizing utility regulation as a "regulatory experiment" that deserved a "fair trial as a substitute for government ownership and operation"); Walton H. Hamilton, *Price—By Way of Litigation*, 38 COLUM. L. REV. 1008, 1031 (1938) (noting that the determination of rates could hardly be "plucked from the air or conjured out of any system of accounts"; rather, it could only emerge through "experimentation" and "trial and error"). Writing in the 1930s, Felix Frankfurter reflected that public utility law had "made possible, within a selected field, a degree of experimentation in governmental direction of economic activity of vast import and beyond any historical parallel." William J. Novak, *Law and the Social Control of American Capitalism*, 60 EMORY L.J. 377, 404 (2010) (quoting Felix Frankfurter & Henry M. Hart, Jr., *Rate Regulation*, *in* 13 ENCYCLOPAEDIA OF THE SOCIAL SCIENCES 104 (Edwin R.A. Seligman & Alvin Johnson eds., 1934)); *see also* Boyd, *supra* note 13, at 1645–51 (discussing early "experimentalist" understanding of public utility and rate regulation).

58. This was the basis for what has sometimes been referred to in more recent years as the "regulatory compact." *See, e.g.*, 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 (coupled with state-conferred rights of eminent domain or condemnation) is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market.").

59. For a description of rate proceedings, see REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE U.S.: A GUIDE 38–58 (2011).

60. *See, e.g.*, DOUGLAS D. ANDERSON, REGULATORY POLITICS AND ELECTRIC UTILITIES: A CASE STUDY IN POLITICAL ECONOMY 64–65 (1981) (discussing elements of formal cost-of-service ratemaking process).

61. *Id.*

62. On "prudent investment," see, for example, JAMES C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 223 (2nd ed. 1988); CHARLES F. PHILLIPS, JR., THE REGULATION

traditional cost-of-service model of ratemaking that dominated public utility regulation up until the advent of electricity restructuring in the mid-1990s.[63] It remains central in those states that have continued to employ the traditional model of electricity regulation and is still used by restructured states in their efforts to regulate local distribution systems and by hybrid states in setting retail rates, including charges for distribution systems.

In addition to their role in setting rates and terms of service provided by individual utilities, PUCs were also given the power to initiate investigations and proceedings on their own accord.[64] Together with individual rate cases, these general investigations and proceedings have provided the primary means for experimenting with new rate designs and other regulatory reforms. In some cases, moreover, PUCs have used these two procedural pathways in tandem, with individual rate cases providing the initial means for testing new rate designs before moving to more generic proceedings that would apply to all utilities operating in the state.[65]

For much of the twentieth century, though, most PUCs assumed a largely reactive posture focused primarily on adjudicating rate cases. The adjudicative role of PUCs thus came to crowd out their more creative policymaking functions, leading some to suggest that the commissions had entered into a terminal phase of stagnation and decline or succumbed to the inevitability of capture.[66] In reality, the general lack of activity by PUCs during this time likely resulted as much from the fact that electricity prices continued to decline due to increasing

OF PUBLIC UTILITIES: THEORY AND PRACTICE 340–41 (1984). On "used and useful," see R.R. COMM'N OF WIS., PUBLIC UTILITIES: LAWS AFFECTING PUBLIC UTILITIES PASSED BY THE LEGISLATURE OF 1907, at 5 (1907); Gilmore, *supra* note 36, at 519.

63. *See* BONBRIGHT ET AL., *supra* note 62, at 109–10 (describing widespread use of traditional "cost-of-service" approach to ratemaking in the United States).

64. *See* GLAESER, *supra* note 33, at 257–58 (discussing early PUC powers of investigation).

65. When a PUC was unable to pursue its goal through a generic proceeding, it could fall back upon individual rate cases with specific utilities. *See* ANDERSON, *supra* note 60, at 89–132 (discussing New York's experiment with marginal cost pricing in the 1970s and the evolution of approach from a generic proceeding to a utility-specific rate case).

66. MARVER H. BERNSTEIN, REGULATING BUSINESS BY INDEPENDENT COMMISSION 74, 91–95 (1955) (proposing that independent commissions followed a similar life cycle ending in stagnation and decline). On capture, see Jim Rossi, *Public Choice, Energy Regulation and Deregulation*, *in* RESEARCH HANDBOOK ON PUBLIC CHOICE AND PUBLIC LAW 419, 421–22 (Daniel A. Farber & Anne Joseph O'Connell eds., 2010); Gregg A. Jarrell, *The Demand for State Regulation of the Electric Utility Industry*, 21 J.L. & ECON. 269, 271–72 (1978); George J. Stigler, *The Theory of Economic Regulation*, 2 BELL J. ECON. & MGMT. SCI. 3, 3 (1971) ("[A]s a rule, regulation is acquired by the industry and is designed and operated primarily for its benefit."). The idea of capture, of course, had been around for some time. *See* William J. Novak, *A Revisionist History of Regulatory Capture*, *in* PREVENTING REGULATORY CAPTURE: SPECIAL INTEREST INFLUENCE AND HOW TO LIMIT IT 25, 26–32 (Daniel Carpenter & David A. Moss eds., 2014).

economies of scale.[67] PUCs had little need, in other words, to exercise their creative policymaking functions as long as regulated utilities continued to deliver cheap power to their customers.

Observers writing during the middle decades of the twentieth century, however, saw the judicialization of PUCs as a serious problem, and bemoaned the diminishment of PUCs' more creative powers.[68] Courts likely facilitated some of this, with early concerns about delegation and due process pushing commissions to restrain some of their more expansive ambitions and adopt increasingly elaborate procedures. Understaffing, resource constraints, various degrees of capture, and the use of PUCs by governors as political patronage machines surely also contributed to the generally reactive posture of many commissions.[69] In the process, PUCs went from entities created to represent and pursue the public interest to umpires presiding over contests in which the "public" was all too often badly outmatched by utility lawyers.[70]

Up until the 1970s, then, the role of PUCs in electricity regulation was not particularly creative. In general, the overall system worked reasonably well, reflecting what one historian has called the "utility consensus."[71] Utilities built ever-larger plants to capture economies of scale and costs continued to come down accordingly.[72] Declining costs translated into falling prices for electricity

67. *See* Paul L. Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, 17 J. LAW & ECON. 291, 312 (1974) ("Electric utilities, experiencing substantial scale economies and technological improvement through much of the 1950's and 1960's, coupled with only moderate increases in the prices of inputs, were able to maintain or reduce nominal average production costs. Firms could thus maintain or decrease prices for output while achieving increasing profits without resorting to price increases. As long as prices were not going up, regulatory commissions were happy to 'live and let live,' engaging in little or no formal rate of return regulation.").

68. *See* Boyd, *supra* note 13, at 1646–47.

69. *See* William E. Mosher, *Defects of State Regulation of Public Utilities in the United States*, 201 ANNALS AM. ACAD. POL. & SOC. SCI. 105, 107 (1939) (detailing problems with PUC regulation and concluding that "probably no commission in the United States is adequately financed to carry on the broad range of duties prescribed in the law"); *see also* THOMAS K. MCCRAW, PROPHETS OF REGULATION 243 (1984) (noting that all too often "regulatory commissions served as dumping grounds for political hacks and cronies of the governor").

70. *See* Felix Frankfurter & Henry M. Hart, Jr., *Rate Regulation*, *in* THE CRISIS OF THE REGULATORY COMMISSIONS 1, 16 (Paul W. Mac Avoy ed., 1970) ("But in the main the public interest has suffered from too many mediocre lawyers appointed for political considerations, looking to the Public Service Commission not as a means for solving difficult problems of government but as a step toward political advancement or more profitable future association with the utilities."); Mosher, *supra* note 34, at 43 (noting that "[t]he judicial function has encroached upon, if it has not practically supplanted, that of public defender").

71. *See* HIRSH, *supra* note 29, at 11–54 (discussing creation and consolidation of the "utility consensus" in the electric power sector during early and middle decades of the twentieth century).

72. *Id.*; *see also* Joskow, *supra* note 67, at 312.

and healthy demand growth. Most PUCs had little reason to pay much attention to what was happening in the sector, much less to embark upon new endeavors in rate reform. For its part, the federal government played a largely residual role in regulating the limited interstate sales of wholesale electricity and occasional disputes over access to transmission.

C. Crisis and Restructuring

By the early 1970s, however, the system was in crisis. Economies of scale in power generation had been exhausted. The oil shocks of the 1970s resulted in higher fuel costs for utilities, which led to higher electricity prices and reduced electricity demand. And growing concerns about the environmental impacts of power generation led to additional regulation and costly delays for new construction. Together, these developments resulted in much greater scrutiny and criticism of the traditional approach to regulating utilities and setting electricity rates.[73]

PUCs and public utility regulation came under sustained criticism from multiple sides. Utilities and their lawyers could not get rate increases fast enough to protect them from rising energy costs, and for the first time they faced the very real possibility of being denied recovery through rates for some of their investments.[74] Economists of various persuasions emphasized the perverse incentives embedded in the cost-of-service model and the general susceptibility of PUCs to capture.[75] Environmentalists saw waste and inefficiency in the prevailing system of declining block rates, and an industry that was responsible for a large and growing share of the nation's pollution burden.[76]

As the crisis of the 1970s gave way to a growing movement for deregulation during the 1980s, critics of utility regulation pushed to open the sector to competition.[77] Drawing on the experience with deregulation in other industries, advocates for electricity restructuring mounted a concerted effort to introduce

73. For discussion of these developments, see Joskow, *Regulatory Failure*, *supra* note 42, at 149–155, and HIRSH, *supra* note 29, at 55–68.
74. *See* ANDERSON, *supra* note 60, at 70–73 (discussing huge increase in number of rates cases during late 1960s and early 1970s leading to frustrations among utility executives with the limited capacity of utility commissions to respond in a timely fashion).
75. *See* Boyd, *supra* note 13 (discussing economic critiques of public utility regulation); Stigler, *supra* note 66 (discussing capture).
76. *See, e.g.*, ANDERSON, *supra* note 60, at 74–75 (discussing efforts by the Environmental Defense Fund and other environmental groups during the early 1970s to intervene in utility rate cases).
77. *See* Boyd, *supra* note 13, at 1651–58 (discussing economic critiques of public utility law and concomitant push for deregulation).

competition into the wholesale and retail segments of the industry.[78] Congress signaled its general policy preference for competition in a comprehensive package of energy legislation in 1992, amending existing law to relax barriers to entry for independent generators and to enhance FERC's authority to mandate transmission access.[79] In doing so, however, it left largely intact the basic jurisdictional split at the heart of the FPA. By failing to enact a broad statutory overhaul to deregulate the industry and by preserving state jurisdiction, Congress thus left FERC to utilize its existing authority under the FPA to create new markets for wholesale power. States retained their ability to choose whether and how they would participate in these markets.

Following its success in restructuring the natural gas industry, FERC moved to open wholesale electricity to competition in 1996.[80] By mandating open access to transmission and by encouraging utilities to unbundle generation from transmission, the commission sought to promote competition among generators in new wholesale power markets that would, in theory, deliver prices that were just and reasonable. Responding to FERC's invitation and with the blessing of their state regulators, utilities in various regions of the country established new wholesale power markets, growing out of, in several cases, the existing tight power pools that had long facilitated informal cooperation among neighboring utilities.[81] As part of this effort, FERC also encouraged the creation of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) (see Figure 2) to administer nondiscriminatory open-access transmission tariffs for member utilities and to oversee these emerging wholesale

78. *See, e.g.*, Joseph D. Kearney & Thomas W. Merrill, *The Great Transformation of Regulated Industries Law*, 98 COLUM. L. REV. 1323, 1408–09 (1998) (describing the move to deregulate common carriers and public utilities as "[t]he great transformation in regulated industries law," marking a shift from "hostility to competition to the maximum promotion of competition").

79. The Energy Policy Act of 1992 (EPAct 1992) created a new class of independent generators, known as exempt wholesale generators (EWGs), that would not be subject to the requirements of the Public Utility Holding Company Act (PUHCA). EPAct 1992 also amended section 211 of the Federal Power Act giving FERC enhanced authority to mandate "wheeling" or transmission access for third parties. *See* Energy Policy Act of 1992, Pub. L. No. 102-486, § 721, 106 Stat. 2776, 2915 (1992) (amending Section 211 of the Federal Power Act); *id.* at §§ 724–26, 106 Stat. 2920–21 (1992) (creating new category of exempt wholesale generators).

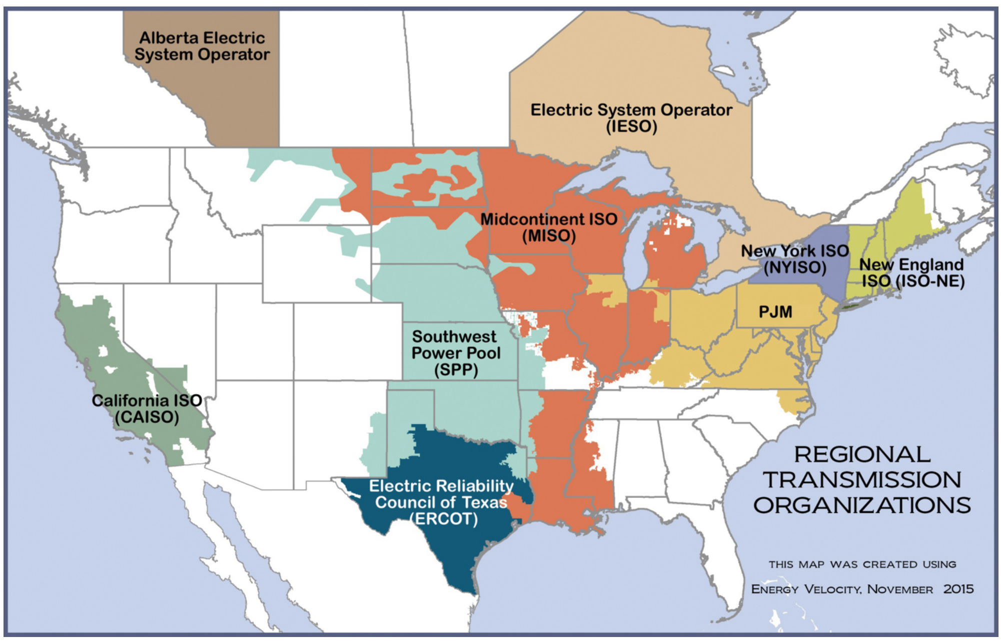
80. *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540, 21541–43 (May 10, 1996) (to be codified at 18 C.F.R. pt. 35) (summarizing final rules designed to require open access non-discriminatory transmission service in order to promote competitive wholesale power markets).

81. *See, e.g.*, JEREMIAH D. LAMBERT, CREATING COMPETITIVE POWER MARKETS: THE PJM MODEL 23–101 (2001) (tracing PJM's history from the first tight power pool agreement in 1927 to FERC authorization as Regional Transmission Organization (RTO) in 1997).

power markets.[82] As these markets took shape, a new class of independent power producers or merchant generators entered to compete with incumbent utilities.

But not all states endorsed FERC's restructuring efforts, leaving a patchwork of organized wholesale markets across the country. Indeed, as Figure 2 below illustrates, large areas of the southeastern and western United States continue to operate outside of these RTO/ISO markets.[83]

FIGURE 2. MAP OF RTOS AND ISOS



At the same time that FERC was seeking to open wholesale power markets to competition, a number of states began to move forward with efforts to restructure their retail electricity markets, giving customers the ability to choose their electricity provider based on different pricing options and services. During the late 1990s roughly half of all states had initiated or were planning to initiate some

82. *See id.*; Regional Transmission Organizations, 65 Fed. Reg. 810, 876–77 (Dec. 20, 1999) (to be codified at 18 C.F.R. pt. 35) (discussing function of RTOs in designing and administering open access transmission tariff).

83. Map is available at *Regional Transmission Organizations (RTO)/Independent SystemOperators (ISO)*, FED. ENERGY REGULATORY COMM'N, http://www.ferc.gov/industries/electric/indus-act/rto.asp [https://perma.cc/Q68U-VL69] (last visited Mar. 20, 2016).

version of retail competition.[84] But in the wake of the California electricity crisis of 2000–2001, with supply shortages, capped retail rates, blackouts, and the bankruptcy of Pacific Gas & Electric, many states retreated from retail competition.[85] Today, only sixteen states, including Texas and most of the northeastern and mid-Atlantic states, have competitive retail electricity markets.[86] And even in these states, most residential consumers simply default into the incumbent utility and most continue to pay flat rates.[87]

Thus, whereas the overall goal of electricity restructuring was fully competitive wholesale markets across the entire country with retail competition in all fifty states, the result was a messy, uneven process that never fully replaced the traditional cost-of-service model. Despite three pieces of omnibus energy legislation

84. *See* Paul L. Joskow, *The Difficult Transition to Competitive Electricity Markets in the United States, in* ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES 1, 32 (James M. Griffin & Steven L. Puller eds., 2005).

85. There is a voluminous literature on the California electricity crisis. *See, e.g.*, CHRISTOPHER WEARE, THE CALIFORNIA ELECTRICITY CRISIS: CAUSES AND POLICY OPTIONS 1–2 (2003) (describing the severe malfunctioning of the California electricity market beginning in the late spring of 2001); Severin Borenstein, *The Trouble With Electricity Markets: Understanding California's Restructuring Disaster*, 16 J. ECON. PERSP. 191, 198–200 (2002) (discussing substantial increases in California wholesale power prices in summer of 2000); Paul L. Joskow, *California's Electricity Crisis*, 17 OXFORD REV. ECON. POL'Y 365, 365, 377–78 (2001) (discussing increases in wholesale electricity prices in California); Frank A. Wolak, *Diagnosing the California Electricity Crisis*, 16 ELECTRICITY J. 11, 20 (2003) (noting that "average market performance over the first two years of the market, from April 1998 to April 2000, was close to the average competitive benchmark price" and compared favorably to performance in the eastern ISOs); *see also* Joel B. Eisen, *Regulatory Linearity, Commerce Clause Brinksmanship, and Retrenchment in Electric Utility Deregulation*, 40 WAKE FOREST L. REV. 545, 557–58 (2005) ("In the aftermath of competition's disastrous failure in the early 2000s in California, states are beginning to slow, alter, or even reject progress toward restructuring, even where it had been embraced earlier."); Joskow, *supra* note 84 (reporting that in the wake of the California electricity crisis no additional states had announced plans to pursue electricity restructuring and nine states that had planned to implement reforms had "delayed, canceled, or significantly scaled back their electricity competition programs"); David B. Spence, *The Politics of Electricity Restructuring: Theory vs. Practice*, 40 WAKE FOREST L. REV. 417, 417 (2005) ("California's disastrous experience with restructured electricity markets has given pause to restructuring's proponents and ammunition to restructuring's opponents.").

86. *See Status of Electricity Restructuring by State*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html [http://perma.cc/Y46X-TSAT] (last updated Sept. 2010).

87. In contrast to limited switching by residential customers, commercial and industrial users have taken more advantage of retail choice. *See State Electric Retail Choice Programs Are Popular With Commercial and Industrial Customers*, U.S. ENERGY INFO. ADMIN. (May 14, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=6250 [http://perma.cc/8D87-3GVG] ("While residential customer participation rates are low in almost all of these [restructured] states, a majority of commercial customers have signed up with competitive suppliers in 9 states and a majority of industrial customers have signed up in 12 states."); *see also id.* ("The highest participation rates are found in the Northeast, Mid-Atlantic states, and Texas where electricity is supplied through Regional Transmission Organizations (RTOs) and states have unbundled generation from retail delivery and sales.").

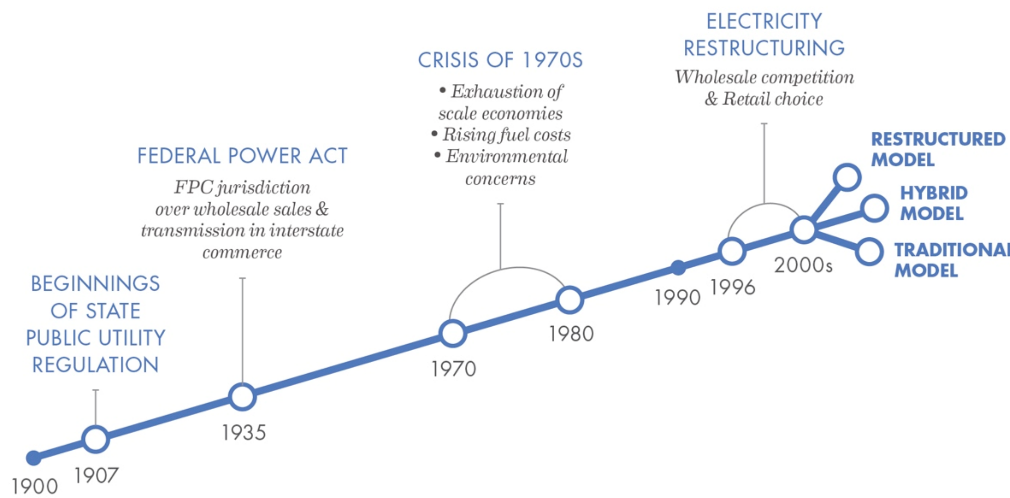
in 1992, 2005, and 2007, moreover, Congress never embarked on the kind of comprehensive statutory overhaul needed to fully restructure the sector.[88] And when FERC sought to push wholesale restructuring further in the early 2000s with its Standard Market Design rulemaking, it became very clear during the negotiation and drafting of the 2005 energy legislation that FERC would either have to suspend the rulemaking or face a provision in the new legislation forcing it to do so.[89] In contrast to its efforts in other sectors such as telecommunications, Congress has decided to leave the basic jurisdictional split in the FPA largely intact, giving states considerable authority to decide whether and how they will engage (if at all) in electricity restructuring.[90] The overall result is three different models of electricity regulation: traditional, restructured, and hybrid (see Figures 3 and 4 below).

88. Energy Policy Act of 1992, Pub. L. No. 102–486, 106 Stat. 2776; Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594; Energy Independence and Security Act of 2007, Pub. L. No. 110–140, 121 Stat. 1492.

89. *See* Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55452 (Aug. 29, 2002) (to be codified at 18 C.F.R. pt. 35). This came to be known as Standard Market Design (SMD) rulemaking. FERC terminated the rulemaking in 2005 in response to pressure from Congress, which was considering multiple draft provisions as part of Energy Policy Act of 2005 (EPAct 2005) that would have prohibited or delayed finalization of the SMD rulemaking. *See* Order Terminating Proceeding, 70 Fed. Reg. 43140 (July 26, 2005). *See generally* Jessica Bulman-Pozen, *Federalism as a Safeguard of the Separation of Powers*, 112 COLUM. L. REV. 459 (2012).

90. Recent developments have strained this jurisdictional split and the federal courts have been called upon to clarify the jurisdictional divide between FERC and the states. *See, e.g.*, FERC v. Elec. Power Supply Assoc., 136 S. Ct. 760, 765 (2016) (noting that the statutory division between federal and state jurisdiction over wholesale and retail rates respectively "generates a steady flow of jurisdictional disputes because—in point of fact if not in law—the wholesale and retail markets in electricity are inextricably linked"); *id.*, at 773 (holding that FERC has statutory authority "to regulate wholesale market operator's compensation of demand response bids"); PPL Energyplus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014), *cert. granted*, 136 S.Ct. 356 (2015), *and cert. granted*, 136 S. Ct. 382 (2015) (holding that the Federal Power Act preempts states in RTO and ISO markets from creating additional out-of-market payments to induce building of new generation capacity); New York v. FERC, 535 U.S. 1, 28 (2002). *See generally* Jim Rossi, *supra* note 45 (arguing that the model of dual sovereignty embedded in the Federal Power Act is giving way to model of concurrent jurisdiction).

FIGURE 3. KEY DEVELOPMENTS IN U.S. ELECTRICITY REGULATION



D. Three Models of Electricity Regulation

These three models of electricity regulation operate across a range of different states. The traditional cost-of-service model, in which vertically integrated IOUs provide service to captive customers through regulated monopoly franchises, remains dominant among states in the Southeast and much of the West. The fully restructured model, which combines wholesale power markets managed by RTOs or ISOs with retail electric competition in individual states, has been adopted by Texas and a number of northeastern and midwestern states.[91] The remaining states operate under a hybrid model, which combines wholesale power markets managed by RTOs or ISOs with retail service provided by IOUs through regulated monopoly franchises.[92] With the exception of Texas, Alaska,

91. *See Status of Electricity Restructuring by State*, *supra* note 86.

92. For a map of current regional transmission organizations (RTOs) and ISOs, see *Regional Transmission Organizations (RTO)/Independent Systems Operators (ISO)*, *supra* note 83. To make matters even more complicated, although most states fall exclusively into one of the three models, some actually participate in two models at the same time. Thus, for example, Arkansas and

and Hawaii,[93] which operate largely outside of FERC jurisdiction, each of these three models blends (or integrates) federal and state authority in distinctive ways.[94] And each, as we show in more detail below, continues to rely upon PUC ratemaking in important ways.

1. Traditional Model

Twenty U.S. states continue to regulate electricity under a traditional cost-of-service model across all or some of their territories.[95] Major utilities in these states are vertically integrated, selling services that bundle together generation, transmission, and distribution. Rates are established through the typical rate case procedure discussed above with the general aim of providing utilities with a reasonable rate of return while guaranteeing customers access to electricity at stable prices.[96] While utilities in traditional states do not participate in organized wholesale electricity markets, they do engage in bilateral wholesale contracting through long-term Power Purchase Agreements and short-term balancing transactions to satisfy some of their power needs.[97]

PUC regulation is at its maximum in these states, with considerable authority to use ratemaking and rate design to pursue various goals. Most residential customers in these states, however, continue to pay flat rates, although a number of these states do offer alternative rate plans, including time-of-use rates, and some have engaged in various rate reform efforts to improve utility performance. As we describe in Part II, the most innovative ratemaking efforts in some

Mississippi regulate some utilities in their states under the traditional model while other utilities that have chosen to participate in the regional wholesale power market managed by MISO are regulated under the hybrid model.

93. Because these three states operate largely outside of federal jurisdiction we have not focused extensively on them in this Article.

94. *Cf.* Gerken, *supra* note 19.

95. As illustrated by the map in Figure 2 above, sixteen states in the continental U.S. have very little or no contact with wholesale electricity markets. Four additional states have some utility service territories that are outside of the wholesale power markets. *See Regional Transmission Organizations (RTO)/Independent Systems Operators (ISO)*, *supra* note 83 (map of RTOs and ISOs). None of the twenty offer retail competition in their electricity markets with the exception of Oregon, which offers choice to large industrial and commercial customers. *See Annual Baseline Assessment of Choice in Canada and the United States*, DISTRIBUTED ENERGY FIN. GRP. 16–17 (2014), http://www.competecoalition.com/files/ABACCUS-2014-vf.pdf [http://perma.cc/3PN3-VHMQ].

96. *See* ELEC. ENERGY MKT. COMPETITION TASK FORCE, REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY 11, http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf [http://perma.cc/3B6M-HPZZ] (describing the cost-of-service model for states that do not participate in wholesale markets).

97. *Id.* at 3 (describing bilateral sales contracts, which predominate in the northwest and southeast).

traditional states has been in the area of advanced cost recovery for large-scale, risky generation projects such as new nuclear or coal with carbon capture and storage.

2. Restructured Model

The fully restructured model combines competitive wholesale power markets with retail choice in the provision of electricity service. This was the model that advocates of restructuring hoped would be adopted across the entire country.[98] States operating under this model are located in regions covered by RTOs or ISOs that administer markets for wholesale power and also coordinate and manage the bulk transmission system across large interstate areas. The map in Figure 2 above depicts the RTOs and ISOs in the U.S. and parts of Canada.

Together with Washington, D.C., sixteen states, largely in the Northeast and Texas, fall into this category.[99] PUCs continue to play an important role in these states in setting rates for use of local distribution systems, certifying retail providers, setting rules on the kinds of rates, though not typically the price, that retail providers can offer, and establishing standard-offer default or provider-of-last-resort service for those customers who choose not to switch or are unable to do so.[100]

In restructured states, Retail Electricity Providers (REPs) buy electricity in the wholesale markets, either through auction or through longer-term Power Purchase Agreements with electricity generators. REPs then compete for retail customers along a number of dimensions, most importantly price. Though the PUC's role is less involved than in traditional states, it remains quite important not only in certifying electricity providers but in setting the rules under which REPs can operate. These rules can cover a range of subjects, including requiring REPs to offer time-variant rates and smart meters, to procure set percentages of renewable energy, and to offer net metering or other incentives for distributed generation. REPs, in other words, remain subject to a wide range of regulatory requirements with the exception of the actual setting of rates for their retail sales of electricity. Moreover, customers who do not choose their REP (most residential consumers) are assigned to a default service provider (sometimes known as

98. *See* discussion *supra* note 79–80.

99. *Annual Baseline Assessment of Choice in Canada and the United States*, *supra* note 95.

100. In retail-choice states, consumers who fail to choose a retail provider are defaulted into a standard-offer or provider-of-last-resort contract, often with the incumbent utility, that is regulated more heavily than contracts with other retail providers. *See* STEVEN BRAITHWAIT ET AL., RETAIL ELECTRICITY PRICING AND RATE DESIGN IN EVOLVING MARKETS 23 (2007).

the provider of last resort), typically the incumbent utility. PUCs often exert more traditional rate-setting authority over these residential rates, an authority that remains quite important because the bulk of residential customers in most restructured states remain with the default service provider.[101]

PUCs in restructured states also continue to regulate the distribution system. Because this part of the system exhibits natural monopoly characteristics, it is still regulated under traditional cost-of-service principles.[102] In most restructured states, the incumbent utility serves as the distribution utility, in addition to providing the default services mentioned above. As discussed in more detail below, a number of PUCs in restructured states are using their ratemaking authority over the distribution system to drive grid modernization.[103] They are also using their authority over the rates paid by customers of the default service provider (typically the distribution utility) to encourage shifts in electricity use away from peak usage.

3. Hybrid Model

Twelve states, including most of the Midwest and mid-Atlantic states and California, operate with a hybrid model that combines competitive wholesale electricity markets with the traditional IOU franchise at the retail level.[104] Like the restructured states, these hybrid states are located in regions with organized wholesale power markets. The major difference between traditional states and hybrid states is that regulated utilities in hybrid states have the option to purchase power through wholesale power markets administered by the RTOs or ISOs, do not have any operational control over their transmission systems, and do not control how power is dispatched over that system. PUCs in these states continue to set retail rates largely in the same fashion as traditional states and have significant power over rate design. They have less ability than traditional states, however, to

101. *See* BRAITHWAIT ET AL., *supra* note 100; *Certification and Licensing: REP—Retail Electric Providers Certification and Reporting*, PUB. UTILS. COMM'N TEX., https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx [https://perma.cc/6LKT-YK26] (last visited Mar. 20, 2016); *Electricity Primer—The Basics of Power and Competitive Markets: How Is Electricity Sold at Retail?*, ELEC. POWER SUPPLY ASS'N, https://www.epsa.org/industry/primer/?fa=sold [https://perma.cc/FK8X-QNSL] (last visited Mar. 20, 2016).

102. *See* THE REGULATORY ASSISTANCE PROJECT, *supra* note 59, at 10.

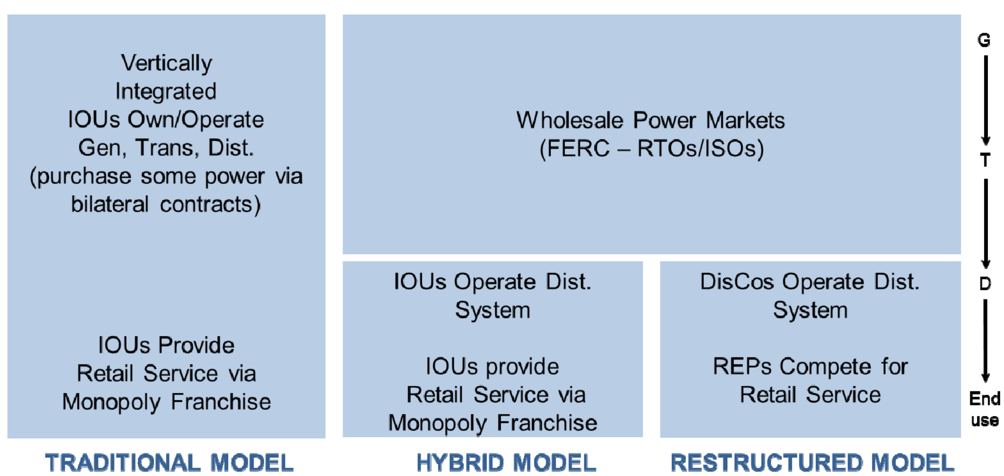
103. *See infra* Part II.B.

104. Twenty-eight states in the continental United States participate in wholesale electricity markets governed by RTOS or ISOs. *See Regional Transmission Organizations (RTO)/Independent Systems Operators (ISO)*, *supra* note 83 (map of RTOs and ISOs). Of the twenty-eight states operating in wholesale markets, sixteen offer competitive retail rates to their consumers. *See State-by-State Information*, *supra* note 95.

influence utility sources of generation capacity since utilities in these states participate in wholesale markets.[105] Some innovative hybrid states, as we describe below, are harnessing their IOUs to modernize the grid, promote distributed energy resources, and alter retail customer energy usage through time-variant rates.

In sum, and as elaborated in the chart below (see Figure 4), there is no single overarching regulatory framework governing electricity in the United States. Instead there is a messy, complex system that can usefully be divided into three major models. This was certainly not the result that advocates of electricity restructuring anticipated or desired.[106] The standard narrative has been that this messy system is problematic, standing in the way of a more rational, efficient, and even environmentally beneficial system of electricity regulation.[107] Our view, however, is that there may be some underappreciated virtues in this three-model system and that the current system may in fact have greater potential for policy experimentation and innovation across various aspects of the power sector than might have occurred under a single, uniform approach. We will return to this topic in Part III below.

FIGURE 4. THREE MODELS OF ELECTRICITY REGULATION



105. For a description of RTO and ISO responsibility for power dispatch, transmission and wholesale markets, see ELEC. ENERGY MKT. COMPETITION TASK FORCE, *supra* note 96, at 30–31.
106. *See* discussion *supra* note 79–80.
107. *See* sources cited *supra* note 16.

E. The Continuing Relevance of Ratemaking

The potential for policy experimentation and innovation across the three models of electricity regulation, we argue, is most apparent in the area of ratemaking and rate design.[108] In all three of the models we identify, some PUCs are using their ratemaking powers in innovative ways that offer valuable experiences for any effort to decarbonize the power sector. Indeed, even fully restructured states are using ratemaking and rate design in important ways, including as a driver of grid modernization, the promotion of distributed energy resources, and adoption of time-variant pricing.[109]

Despite its continuing relevance across the power sector, however, ratemaking has received limited attention from policymakers and legal scholars.[110] This likely reflects, at least in part, the fact that most of the attention over the last two decades has focused on the introduction of competition into various segments of the industry and the concomitant challenges of designing and regulating well-functioning markets for electricity. These electricity restructuring efforts (at wholesale and retail levels) have generally proceeded on the assumption that robust competition in the sector would result in just and reasonable rates and, accordingly, that the market would largely replace the previous regulatory task of designing and setting rates.[111]

That assumption has proven mistaken for at least two reasons. First, as we have described, the actual course of electricity restructuring in the United States has been uneven, leaving large segments of the country without any competitive markets at either wholesale or retail levels. Second, even in those parts of the country that have made the transition to robust wholesale and retail competition,

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108. We use the term ratemaking here to refer to the general practice of setting rates (or prices) for electricity as understood in traditional public utility regulation and as described *infra* Part I.B. In simplest terms, ratemaking involves establishing the total revenue required for the utility to cover its cost of service (including earning a rate of return) and then allocating or structuring rates among different classes of customers (industrial, commercial, residential) in a manner intended to ensure that the utility meets its overall revenue requirement. This practice of structuring rates between and among customer classes is typically referred to as "rate design." Thus, rate design can be considered a subset of the more general practice of ratemaking.

109. *See* discussion *infra* Parts II.B, II.C, II.D.

110. Of course, this has not always been the case. During the early twentieth century, ratemaking and rate regulation more generally were of major interest to Progressive lawyers and legal scholars, institutional economists, and several prominent legal realists. *See* Boyd, *supra* note 13, at 1636–51 (discussing this history). During the 1960s and 1970s, moreover, the traditional model of rate regulation was the subject of a series of hard-hitting critiques from economists and legal scholars. *Id.* at 1651–58 (discussing some of these critiques).

111. *See, e.g.*, Spence, *supra* note 85, at 418–27 (discussing theoretical and political cases for restructuring and the goal of using competition rather than regulation to control prices).

PUCs continue to grapple with important ratemaking issues involving the distribution system, incentives for distributed energy resources, time-variant rates, and the rates that customers who refuse to choose a retail electricity provider will pay to the distribution utility that offers default services.[112] Ratemaking, in short, is here to stay.

While these topics of rate regulation have long been viewed as technical subjects best left to economists and engineers (and they are highly technical), it is crucial to recognize that questions and choices regarding electricity rates are fundamental to the broader policy issues affecting the sector.[113] They determine whether or not certain technologies and fuels move forward and at what speed. They reward or penalize certain practices and business models. And they provide incentives for a whole range of consumer behavior. In effect, by adjusting the bundle of entitlements that structures the enterprise of public utility, electricity rates change the way the grid operates. Part of our argument is that the three-model system of electricity regulation that has emerged in the wake of restructuring might provide an expanded set of opportunities to experiment with different rate designs affecting different aspects of the grid when compared to those available under a single, national framework—and at precisely the moment when the sector is undergoing rapid technological change and facing new environmental constraints. The next Part develops four case studies of ratemaking innovations among the three models and across different aspects of the power sector in support of this claim.

II. RATEMAKING AND POLICY INNOVATION FOR A LOW-CARBON FUTURE

Efforts to decarbonize the electricity sector, we argue, will need to harness the power of ratemaking in multiple ways. By determining the relationship that residential, commercial, and industrial end-users have to the grid (and to the various actors involved in the generation, transmission, and distribution of electricity), retail electricity rates influence what kind of generation will be built, how and when customers will use electricity, and what kinds of activities will be promoted or penalized. As efforts to decarbonize the electric power sector proceed at state and federal levels, ratemaking and rate design will thus become increasingly important topics for regulators, utilities, and various third parties, especially in the

112. *See* discussion *infra* Parts II.B, II.C, II.D.
113. *See* RICHARD WHITE, THE ORGANIC MACHINE: THE REMAKING OF THE COLUMBIA RIVER 67 (1990) (describing public utility regulation and ratemaking as "technical and abstract"—"exactly the kinds of issues that make the eyes glaze and the mind wander").

context of widespread deployment of distributed energy resources and a more participatory, multi-directional distribution system.[114]

In various ways over the last several decades, the federal government has encouraged states to use their ratemaking powers to innovate. Some of these efforts have involved explicit policy nudges in federal energy legislation. The Public Utility Regulatory Policy Act of 1978 (PURPA), for example, created a program that required utilities to purchase power from small renewable energy and cogeneration facilities (Qualifying Facilities or QFs) and authorized states to develop avoided-cost rate schedules to compensate these generators.[115] Some states, such as California, responded by developing generous long-term QF contracts that led to significant growth in renewable energy.[116] PURPA also encouraged states to deploy time-of-use rates and other rate designs to promote conservation and efficiency.[117] The 2005 Energy Policy Act[118] required states to consider adding advanced metering in order to implement more effective time-based pricing and pushed states to offer net metering programs for distributed generation.[119]

Other federal interventions have come in the form of direct financial subsidies. The American Reinvestment and Recovery Act Smart Grid Investment Program, for example, has subsidized the installation of more than sixteen million smart meters across the country with smart grid expenditures totaling almost $4.4 billion and funded time-variant rate pilot programs in every region of the country.[120] And the Department of Energy has provided more than $13 billion in loan guarantees and other incentives for new nuclear power plants in Georgia

114. *See generally* DEVI GLICK ET AL., RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE (2014).

115. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95–617, § 210, 92 Stat. 3117, 3144–47.

116. *See* HIRSH, *supra* note 29, at 89, 94–98 (discussing state approaches to PURPA's QF program and lucrative QF contracts in California).

117. 16 U.S.C. § 2621(d) (2012).

118. Pub. L. No. 109-58, 119 Stat. 594 (2005).

119. *See* KENNETH ROSE & KARL MEEUSEN, REFERENCE MANUAL AND PROCEDURES FOR IMPLEMENTATION OF THE "PURPA STANDARDS" IN THE ENERGY POLICY ACT OF 2005, at 10 (2006).

120. *See Advanced Metering Infrastructure and Customer Systems*, SMARTGRID.GOV, https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.html## [https://perma.cc/ZK8D-VU6D] (last updated Mar. 13, 2015). This was also matched by private investment of roughly the same amount, resulting in a combined investment of almost $10 billion in advanced metering infrastructure around the country. For a description of dynamic pricing pilot programs funded by the federal government, see U.S. DEP'T OF ENERGY, AMERICAN RECOVERY AND INVESTMENT ACT OF 2009: EXPERIENCES FROM THE CONSUMER BEHAVIOR STUDIES ON ENGAGING CUSTOMERS 1–2 (2014) (describing and evaluating pilot programs); *Consumer Behavior Studies*, SMARTGRID.GOV, https://www.smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html [https://perma.cc/45EE-63FF] (last visited Mar. 20, 2016).

and South Carolina,[121] and hundreds of millions of dollars in grants and tax subsidies for a carbon capture and sequestration plant in Mississippi.[122] Each of these federal nudges is, as we describe below, playing a role in partially de-risking various experiments in a number of states across all three models of electricity regulation.

EPA's rules for existing power plants under section 111(d) of the Clean Air Act—one of the more ambitious environmental regulatory programs EPA has ever issued—also recognize the importance of ratemaking and rate design in reducing emissions.[123] The Clean Power Plan gives states considerable flexibility in developing required plans to reduce emissions across the power sector rather than exclusively at each individual source.[124] By going "outside the fenceline" of individual power plants and allowing states to devise compliance strategies that take account of the interconnected nature of the electric power system, the Clean Power Plan will inevitably call upon the ratemaking power of PUCs.

This Part examines four areas in which states are using their ratemaking powers to experiment with important components of the electric power system: (1) advanced, low-carbon baseload generation; (2) grid modernization; (3) distributed energy resources; and (4) time-variant rates. All of these areas have potentially crucial roles to play in any transition to a low-carbon future. The discussion that follows identifies particularly innovative examples in each area, focusing on why certain experiments are emerging in certain kinds of states. It also describes the advantages and disadvantages each model of regulation might have to promote certain kinds of investments and behaviors. This section also examines the specific role PUCs play in driving innovation in these four areas, situating them within the broader landscape of actors involved in state public utility

121. In addition to loan guarantees, EPAct 2005 also provided regulatory risk insurance for the first six new reactors licensed by the Nuclear Regulatory Commission (NRC) and production tax credits for new nuclear units placed in service by 2021. *See* LARRY PARKER & MARK HOLT, CONG. RESEARCH SERV., NUCLEAR POWER: OUTLOOK FOR NEW U.S. REACTORS, CRS-10 to 13 (2007).

122. *See Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project*, MASS. INST. TECH., http://sequestration.mit.edu/tools/projects/kemper.html [https://perma.cc/2N9UMPAA] (last updated Mar. 1, 2016) [hereinafter *Kemper County IGCC Fact Sheet*].

123. *See* EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units, 80 Fed. Reg. 64,662, 64,832–38 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60) (discussing different approaches that states can take in their state plans to demonstrate compliance). On February 9, 2016, the U.S. Supreme Court issued a stay of the Clean Power Plan pending a Supreme Court judgment on the merits or a denial of a petition for review by the Court. Order in Pending Case, West Virginia v. EPA, Order No. 15A773 (Feb. 9, 2016), http://www.scotusblog.com/wp-content/uploads/2016/02/15A773-Clean-Power-Plan-stay-order.pdf.

124. *Id.*

law. We conclude by discussing some general lessons from these cases for institutional design and their relevance to our broader arguments regarding federalism and experimentation in the Part that follows.

A. Advancing Low-Carbon Baseload Generation

"Too cheap to meter." That was the line atomic energy boosters sometimes used during the 1950s at the dawn of the commercial nuclear power industry in the United States.[125] Had it turned out to be true, there would be no need for special rates or innovative cost recovery mechanisms to promote nuclear power. But, of course, the hope that nuclear power would provide cheap and virtually unlimited power never materialized.

Fission-based reactors are enormously complicated machines to construct and operate. They take years to build and cost huge sums of money.[126] The "too cheap to meter" refrain likely referred to the dreams that various nuclear enthusiasts had of commercial *fusion* reactors, which are still apparently twenty years away.[127] In the 1960s, with demand for electricity growing at a robust pace, utilities built *fission*-based reactors as fast as they could get approval to do so. By 1974, 54 commercial reactors were operating in the United States with almost 200 more on order.[128] Six years later, in the wake of the energy crisis and the 1979 accident at Three Mile Island, the bloom was off the rose and some utilities abandoned their nuclear construction projects, leaving billions of dollars on the table.[129] Much of this became

125. The phrase is attributed to Lewis Strauss, appointed by President Truman as one of the original members of the Atomic Energy Commission (AEC) and by President Eisenhower to be Chairman of the AEC in 1953. Here is what he actually said: "Our children will enjoy in their homes electrical energy too cheap to meter. . . . [They] will travel effortlessly over the seas and under them and through the air with a minimum of danger and at great speeds, and will experience a life span far longer than ours, as disease yields and man comes to understand what causes him to age." *Abundant Power From Atom Seen*, N.Y. TIMES, Sept. 17, 1954, at 5 (quoting Strauss from a speech to the National Association of Science Writers).

126. Lucas W. Davis, *Prospects for Nuclear Power*, 26 J. ECON. PERSP. 49, 53 (2012) ("Nuclear power plants are enormous facilities with high construction costs.").

127. *See, e.g.*, Michael Brooks, *Forever Twenty Years Away: Will We Ever Have a Working Nuclear Fusion Reactor*, NEW STATESMAN (Nov. 6, 2014), http://www.newstatesman.com/sci-tech/2014/11/forever-20-years-away-will-we-ever-have-working-nuclear-fusion-reactor [http://perma.cc/TRG8-Z9JP]; Charles Seife, *Fusion Energy's Dreamers, Hucksters, and Loons: Bottling Up Power of Sun Will Always Be Twenty Years Away*, SLATE (Jan. 3, 2013), http://www.slate.com/articles/health_and_science/nuclear_power/2013/01/fusion_energy_from_edward_teller_to_today_why_fusion_won_t_be_a_source_of.html [http://perma.cc/7R6P-WKYK].

128. Lucas W. Davis, *Prospects for Nuclear Power* 2 (Nat'l Bureau of Econ. Research, Working Paper No. 17674, 2011) (reporting 54 operating reactors and 197 orders for new reactors as of 1974).

129. Prior to the recent orders for new nuclear reactors (all of them post–2007), the last order for a new nuclear unit in the United States was in 1978 and that order, along with every other order after

the subject of disputes with regulators and ratepayer advocates about whether these costs could be recovered in rates even though the facilities would never be "used and useful."[130] After several billion dollars in disallowances, a fair amount of litigation, and some very large hits to utility credit ratings, utility management and their regulators moved on.[131]

Today, there are ninety-nine nuclear reactors operating in the U.S.—down from 104 a few years ago—that collectively provide close to 20 percent of total electricity generation.[132] These plants provide cheap, highly reliable baseload power (which means they run around the clock).[133] Notwithstanding the important and still unresolved questions about what to do with spent nuclear fuel and how to handle the risk of accidents, nuclear power produces zero emissions.[134] No sulfur dioxide, nitrogen oxides, or particulate matter. No mercury or volatile organic compounds. And no carbon dioxide.

But the "youngest" nuclear power plant in operation in the United States today is almost twenty years old and the average age of the fleet is thirty-five.[135] Most

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1973, was eventually canceled. More than 120 reactor orders were eventually canceled. *See* PARKER & HOLT, *supra* note 121, at 1, 3.

130. *See, e.g.*, Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989); Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168 (D.C. Cir. 1987).

131. *See* RON BINZ ET AL., CERES, PRACTICING RISK-AWARE ELECTRICITY REGULATION: WHAT EVERY STATE REGULATOR NEEDS TO KNOW 26 (2012) ("Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities. During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame."); *see also* Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 497–98, 500–02 (1984) (discussing problems of overbuilding in the electric power industry in the 1970s).

132. *How Many Nuclear Power Plants Are in the United States, and Where Are They Located?*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/tools/faqs/faq.cfm?id=207&t=3 [http://perma.cc/Q4RS-ABAY] (last updated Jan. 27, 2016) (reporting 61 commercially operating nuclear power plants with a total of 99 nuclear reactors in 30 states); *Monthly Energy Review*, U.S. ENERGY INFO. ADMIN. 129 tbl.8.1 (Oct. 2015) (reporting nuclear share of electricity generation over first seven months of 2015 as 19.5 percent).

133. Paul L. Joskow & John E. Parsons, *The Economic Future of Nuclear Power*, 138 DÆDALUS 45, 47 (2009) (noting that nuclear power plant capacity factors in the United States have increased steadily over the last two decades to over 90 percent).

134. Davis, *supra* note 126, at 63 (noting that "nuclear power is virtually emissions-free" but that "Fukushima has brought to the forefront ongoing concerns about nuclear accidents and the handling and storage of spent fuel"); *see also* MASS. INST. TECH., THE FUTURE OF NUCLEAR POWER 47–63 (2003), http://web.mit.edu/nuclearpower/pdf/nuclearpower-full.pdf (discussing reactor safety and high-level waste management issues).

135. TVA's Watts Bar Unit 1 went on line in 1996, twenty-six years after the project was initiated. Its sister unit, Watts Bar 2, was recently revived and is expected to come on line in 2016. The oldest operating reactors in the United States today are Oyster Creek in New Jersey and Nine Mile Point 1 in New York, both of which entered commercial service on December 1, 1969. The average age

existing plants are thus nearing the end of their initial forty-year licenses and many have already received additional twenty-year license extensions from the Nuclear Regulatory Commission (NRC).[136] While sixty may be the new forty, few want to see nuclear power plants operating much beyond six decades.[137] And regardless of how many license extensions are granted, maintaining nuclear power's share of U.S. generation capacity, much less increasing it, will require new construction.

For a brief moment in the mid-2000s, there was talk of a nuclear renaissance in the United States. At one point, twenty-eight applications for licenses to build and operate new reactors had been filed with the NRC.[138] New reactor designs promised more efficient and safer plants.[139] A streamlined regulatory process would avoid the costly delays of the past,[140] and Congress made various subsidies available for early movers.[141] Then came shale gas, which made the economics of

of the current nuclear fleet is around thirty-five years. *See How Old Are U.S. Nuclear Power Plants and When Was the Last One Built?*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/tools/faqs/faq.cfm?id=228&t=21 [http://perma.cc/8GEP-NPCE] (last updated Feb. 4, 2016).

136. As of January 2016, eighty-four commercial reactors had received twenty-year license renewals from the NRC and another eleven license renewal applications were under review. *See Status of License Renewal Applications and Industry Activities*, U.S. NUCLEAR REG. COMM'N, http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html [http://perma.cc/5NCS-QSXK] (last updated Jan. 29, 2016).

137. But see recent requests from Duke, Exelon, and Dominion to extend operating licenses for some reactors to eighty years. Robert Walton, *Exelon, Duke, Dominion Will Seek to Extend Nuke Plant Licenses to Eighty Years*, UTILITYDIVE (July 20, 2015), http://www.utilitydive.com/news/exelon-duke-dominion-will-seek-to-extend-nuke-plant-licenses-to-80-years/402532 [https://perma.cc/7SLA-MLEF].

138. MARK HOLT, CONG. RESEARCH SERV., NUCLEAR ENERGY POLICY 8–9 tbl.1 (2014).

139. *See, e.g.*, Ioannis N. Kessides, *The Future of the Nuclear Industry Reconsidered: Risks, Uncertainties, and Continued Promise*, 48 ENERGY POL'Y 185, 193–95 (2012) (discussing safety and operational advantages of generation III and III+ reactor designs developed over the last decade and noting that the Westinghouse AP1000 reactor design, a generation II+ design, was certified by the NRC in 2006); *see also* Declan Butler, *Nuclear Power's New Dawn*, 429 NATURE 238, 238–40 (2004) (discussing importance of new advanced reactor designs).

140. In 1989, the NRC issued a streamlined regulatory process that included an early site permit program, standard design certification for new reactor designs, and a combined construction and operating license procedure. *See* Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Reactors, 54 Fed. Reg. 15,372 (Apr. 18, 1989). Congress subsequently endorsed the new licensing procedures in the Energy Policy Act of 1992. *See* Energy Policy Act of 1992, Pub. L. No. 102–486 §§ 2801–07, 106 Stat. 2776, 3120–22 (1992).

141. As noted above, EPAct 2005 provided a range of incentives for new reactors including loan guarantees, regulatory risk insurance for early movers, and production tax credits for new reactors placed in service by 2021. *See* PARKER & HOLT, *supra* note 121, at 10–12.

new nuclear much more difficult, and then Fukushima.[142] By 2012, the so-called nuclear renaissance had stalled.[143]

But a few utilities and a few states soldiered on, pushing forward with plans to build new reactors. In 2012, Georgia Power and its partners received the first NRC licenses issued since 1978 to build two new units at its existing Vogtle plant in Georgia.[144] Soon after, a consortium of companies led by South Carolina Electric and Gas Co. received licenses to construct and operate two new units at the VC Summer plant in South Carolina.[145] South Carolina, incidentally, already receives more than half of its electricity from nuclear energy.[146] All four of the new units have experienced delays and cost overruns. As of late 2015, estimated total costs were $7.5 billion for the two Vogtle units and $7.1 billion for the VC Summer units.[147] All

142. *See* Paul L. Joskow & John E. Parsons, *The Future of Nuclear Power After Fukushima*, 1 ECON. ENERGY & ENVTL. POL'Y 99 (2012); Martin LaMonica, *A Glut of Natural Gas Leaves Nuclear Power Stalled*, MIT TECH. REV. (Aug. 9, 2012), http://www.technologyreview.com/news/428737/a-glut-of-natural-gas-leaves-nuclear-power-stalled [http://perma.cc/UD7T-3927].

143. Davis, *supra* note 126, at 49 (discussing effects of cheap natural gas, global economic recession, and the Fukushima accident on the "nuclear power renaissance").

144. *See* Matthew L. Wald, *Federal Regulators Approve Two Nuclear Reactors in Georgia*, N.Y. TIMES (Feb. 9, 2012), http://www.nytimes.com/2012/02/10/business/energy-environment/2-new-reactors-approved-in-georgia.html [http://perma.cc/8D73-NT2C] (reporting on NRC decision to issue licenses to Georgia Power for two new reactors in Georgia).

145. Ryan Tracy, *U.S. Approves Nuclear Plants in South Carolina*, WALL STREET J. (Mar. 30, 2012, 5:54 PM), http://www.wsj.com/articles/SB10001424052702303816504577313873449843052 [http://perma.cc/J3BE-T62A] (reporting on NRC decision to issue licenses to Scana Corp. for two new reactors in South Carolina).

146. *See South Carolina: Profile Overview*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/?sid=SC [http://perma.cc/MQ7X-AXDX] (last updated May 21, 2015) (reporting that "South Carolina's four existing nuclear power plants supplied 54 percent of the state's net electricity generation in 2014").

147. *See* GA POWER, THIRTEENTH SEMI-ANNUAL VOGTLE CONSTRUCTION MONITORING REPORT 6 tbl.1.1 (2015), https://georgiapower.com/docs/about-energy/13th-VCM-Report-Final.pdf?hp=lnau_box2 [https://perma.cc/7PN2-R9LJ] (reporting total capital cost and financing for Vogtle units 3 and 4 of $7.453 billion); S.C. ELEC. & GAS CO., V.C. SUMMER NUCLEAR STATION UNITS 2 & 3: QUARTERLY REPORT TO THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF SUBMITTED BY SOUTH CAROLINA ELECTRIC & GAS COMPANY PURSUANT TO PUBLIC SERVICE COMMISSION ORDER NO. 2009-104(A), at 33 (2015), https://www.scana.com/docs/librariesprovider15/pdfs/blra-status-reports/3q-2015-blra-report.pdf?sfvrsn=2 [https://perma.cc/K286-UQZ5] (noting projected costs of $7.1 billion for the two V.C. Summer reactors). For comparison, the market capitalization for the Southern Company, which is the parent company of Georgia Power, the company that is leading the consortium building the Vogtle units, was around $42 billion in early 2016. *Southern Co.*, WALL STREET J., http://quotes.wsj.com/SO (last visited Jan. 18, 2016). SCANA corporation, the parent company of South Carolina Electric and Gas, which is leading the consortium of companies building the V.C. Summer plants, has a market capitalization of about $8.6 billion. *Scana Corp.*, WALL STREET J., http://quotes.wsj.com/SCG (last visited Jan. 18, 2016). Figures

four of the new units are, as of late 2015, expected to be completed in 2019 and 2020.[148]

While these first four reactors benefited from federal subsidies and support,[149] illustrating the importance of federal interventions to de-risk certain investments, they were only possible because of extensive rate reform efforts in the host states. Working closely with the utilities, both Georgia and South Carolina enacted legislation that made cost recovery for these types of investments feasible and allowed the financing to proceed.[150] Specifically, the new legislation directed the Georgia and South Carolina PUCs to provide an enhanced version of what is known as "construction work in progress" or CWIP, which allows the utilities to put certain construction expenditures into rate base (and rates) immediately, thereby earning a rate of return on the expenditures that allows the utilities to pay financing charges with money recovered through rates rather than from their own balance sheets.[151] While CWIP has been used in other areas, particularly as an incentive to proceed with transmission investments, it is a departure from the traditional model of rate regulation, which typically prohibits putting any costs associated with a new asset in rate base until the asset itself is "used and useful" (that is, in service and providing electricity to ratepayers).

are taken from the Wall Street Journal website service providing financial data on public companies, dated January 18, 2016.

148. *See Vogtle 3 and 4 Project Overview*, GA POWER, https://www.georgiapower.com/about-energy/energy-sources/nuclear/overview.cshtml [https://perma.cc/TT25-J6T7] (last visited Mar. 20, 2016) (reporting expected start dates of 2019 and 2020 for the two new Vogtle units); *see also* S.C. ELEC. & GAS CO., *supra* note 147, at 31 (reporting "substantial completion" dates of June 2019 for V.C Summer unit 2 and June 2020 for V.C. Summer Unit 3).

149. *See* HOLT, *supra* note 138, at 21–27 (summarizing federal incentives for new nuclear plants, including subsidies available only to the new reactors under construction at Vogtle and VC Summer). *See U.S. Nuclear Power Policy*, WORLD NUCLEAR ASS'N, http://www.world-nuclear.org/information-library/country-profiles/countries-t-z/usa-nuclear-power-policy.aspx (last updated Nov. 2015).

150. *See, e.g.*, Georgia Nuclear Energy Financing Act, GA. CODE ANN. § 46-2-25 (2010); Base Load Review Act, S.C. CODE ANN. § 58-33-210 (2014).

151. *See* GA. CODE ANN. § 46-2-25(c.1)(1) (2010) (providing that utility "shall recover" financing costs of new nuclear generating plants that have been certified by the commission and providing that financing charges shall accrue in the utility's construction work in progress account); S.C. CODE ANN. § 58-33-280(B) (2014) (providing that utility "must be allowed to recover through revised rates its weighted average cost of capital applied to all or, at the utility's option, part of the outstanding balance of construction work in progress"); *id.* at §58-33-280(K) (providing for recovery of construction and financing costs in cases of abandonment of the project as long as utility can show that abandonment was prudent).

The new regulatory frameworks also provide for up-front prudence determinations for these projects, and some protections in case a project is abandoned.[152] In sum, these new plants get accelerated and generous rate treatment and they will not be subject to second-guessing by regulators even if they fail. Think of it as cost-of-service on steroids.

Opponents of these plants have charged that they are a massive give away to the utilities at the expense of ratepayers—one more example of how regulators (and state legislatures) are captured by the industry they are charged with regulating.[153] Maybe. While it is true that the utilities (and their lawyers) were deeply involved in crafting some of this legislation,[154] the utilities themselves are taking on a fair amount of risk in building the first new reactors in the country in more than thirty years. The utilities and their shareholders are already facing negative credit impacts from cost overruns and delays and may ultimately lose the political support necessary to maintain favorable rate treatment.[155] If natural gas prices stay low, moreover, these plants will likely be uneconomic for years. It seems safe to conclude that no company would ever make these investments in the current environment without some protection above and beyond that provided by the traditional cost-of-service model. Whether the choices that the federal government

152. *See, e.g.*, S.C. CODE ANN. § 58-33-225(D), (E), (G), (H) (2014) (providing for prudency determinations of pre-construction costs, recovery of such costs in rates, cost recovery in case of project abandonment, and denying challenge or re-opening of prudency determinations).

153. *See* Direct Testimony of Glenn Carroll on Behalf of Nuclear Watch South Before the Georgia Public Service Commission at 6, *In re* Review of Proposed Revisions and Verification of Expenditures Pursuant to Georgia Power Company's Certificate of Public Convenience and Necessity for Plant Vogtle Units 3 and 4, Thirteenth Semi-annual Construction Monitoring Report (Dec. 10, 2015) (No. 29849) (asserting that Georgia Power is making excess profits from CWIP treatment of Vogtle construction costs, that the state no longer needs the plants, and that ratepayers would be better off if the plants were canceled); Adam Russell, *Another Vogtle Debacle? Cost Overruns, Delays and Construction Woes Bedevil V.C. Summer Reactor Project in S.C.*, FRIENDS OF THE EARTH (Jan. 16, 2014), http://www.foe.org/news/archives/2014-01-another-vogtle-debacle-cost-overruns-delays-and-construction-woes-at-reactor#sthash.ojeTG6Hm.dpuf [https://perma.cc/FB2B-P6EB].

154. *See* Sue Sturgis, *Power Politics: Big Nuclear's Money Grab*, INST. FOR SOUTHERN STUDIES (Mar. 2, 2009), http://www.southernstudies.org/2009/03/power-politics-big-nuclears-money-grab.html [https://perma.cc/M8BL-JR63] (describing intense lobbying efforts by Georgia Power in securing favorable legislation for financing of new nuclear construction).

155. *See, e.g.*, Michael G. Haggarty, *Cost Increases and Delays at Georgia Power's New Nuclear Project Are Credit Negative but Manageable at Current Rating Levels*, MOODY'S (Mar. 11, 2013), https://www.moodys.com/research/Moodys-Cost-Increases-and-Delays-at-Georgia-Powers-New-Nuclear—PR_268207 [https://perma.cc/MV2X-7JA5] (discussing impacts of Vogtle plant cost overruns and delays on Georgia Power's credit rating); David Wren, *State to Review Financing Method for South Carolina Nuclear Plant*, CHARLESTON POST & COURIER (Sept 20, 2015), http://www.postandcourier.com/article/20150920/PC05/150929989/1177/null [https://perma.cc/2LS8-WTEF] (reporting on decision by South Carolina Office of Regulatory Staff to review financing of VC Summer units under Baseload Review Act and effects on customers).

and these states have made to support these investments constitute capture or a form of de-risking may depend on one's perspective.

Moreover, and at least as important, these new reactors would never be built in states operating in hybrid and restructured markets.[156] The sheer scale and long time horizons associated with these investments together with the uncertainty regarding performance, future prices, and regulations translate into a relatively high cost of capital, which makes financing very challenging in the market context. This is particularly true in the current environment of cheap natural gas. Witness the words of John Rowe, former CEO of Exelon Corp., the largest U.S. producer of nuclear power: "As long as natural gas is anywhere near current price forecasts, you can't economically build a merchant nuclear plant."[157] Encouraging the development of nuclear generation in the current environment, in other words, will require creative ratemaking and federal subsidies.

Though one could argue that market forces should determine our energy mix, at this point carbon emissions are largely unregulated and thus fossil fuel-powered electricity has a significant economic advantage over nuclear power. As noted, cheap natural gas from shale has made the economics of nuclear even more challenging.[158] But Georgia and South Carolina have decided that it is worth having their ratepayers assume a portion of the risk of new nuclear investment in order to determine whether nuclear power can continue to be a viable part of their electricity mix. And these states continue to have some of the lowest electricity rates in the country.[159] While their motivation may not be principally about generating zero-carbon electricity, the only way to know if nuclear power can be a key component of efforts to decarbonize the power sector is to build new reactors. That is, the only way to know how well these new reactors will work and how much they will cost is to build them. And it appears that the only place we can build them right now is in traditional cost-of-service states.

156. *See generally* Jay Apt et al., *Promoting Low-Carbon Electricity Production*, 23 ISSUES SCI. & TECH. 37, 41 (2007); Tim Laing & Michael Grubb, *Low Carbon Electricity Investment: The Limitations of Traditional Approaches and a Radical Alternative* 4–7 (Univ. of Cambridge Elec. Policy Research Grp., Working Paper No. 1032, 2010). *See also* Emily Hammond & David B. Spence, *The Regulatory Contract in the Marketplace*, 69 VAND. L. REV. 141 (2016) (discussing challenges of building nuclear reactors in wholesale electricity markets).

157. Mark Clayton, *Nuclear Power a Viable Competitor in US Energy Market, Study Finds*, CHRISTIAN SCI. MONITOR (Sept. 17, 2010) (quoting John Rowe, Exelon CEO), http://www.csmonitor.com/USA/2010/0917/Nuclear-power-a-viable-competitor-in-US-energy-market-study-finds [http://perma.cc/WU25-V66G].

158. Davis, *supra* note 126, at 50 (discussing effects of cheap natural gas on economics of nuclear power).

159. *See State Electricity Profiles*, U.S. ENERGY INFO. ADMIN. (Feb. 8, 2015), http://www.eia.gov/electricity/state [http://perma.cc/7XXJ-HH76] (providing overview of average retail electricity prices by state).

The story is similar with carbon capture and storage (CCS) for coal-fired power plants. One possible technological approach to decarbonizing the power sector, widely endorsed by the fossil fuel industry, is to capture and store (or sequester) in underground reservoirs the carbon emissions from coal-burning power plants (and perhaps one day natural gas plants as well).[160] CCS presents a complicated technological challenge and hard questions about where to put all of the captured CO_2 and whether it will stay underground (not to mention liability, long-term maintenance and monitoring, and so forth).[161] If successful however, CCS could be a game changer here in the United States and especially abroad in countries such as China and India, which have massive coal reserves and rapidly growing emissions and energy requirements.[162] If CCS fails, of course, we need to find alternatives (and fast) if we want to decarbonize. Either way, we need to know if CCS is a viable and economic option.

Although CCS is unlikely to work on existing plants because too much energy is lost with the retrofits,[163] it might be possible to develop a new advanced type of coal plant that would have CCS designed into the machine itself. One of the most attractive technologies in this respect is Integrated Gasification Combined Cycle or IGCC, which essentially transforms coal into synthetic gas that is then burned in a combined cycle gas turbine. The advantage of IGCC is that it makes it easier to separate and capture various streams of emissions, including carbon dioxide. But these plants are also very expensive to build and operate, and

160. *See, e.g.*, Klaus S. Lackner et al., *Eliminating CO_2 Emissions From Coal-Fired Power Plants*, *in* GENERATING ELECTRICITY IN A CARBON-CONSTRAINED WORLD 127–73 (F.P. Sioshani ed., 2010) (reviewing basic features of carbon capture and storage, key technological options, and novel approaches); MASS. INST. TECH., THE FUTURE OF COAL: OPTIONS FOR A CARBON CONSTRAINED WORLD 17–42 (2007) (discussing various coal-based electricity generating options and the feasibility of CO_2 capture for each); *id.* at 43–62 (discussing challenges of geological sequestration of large volumes of captured CO_2 from coal burning power plants).

161. *See* MASS. INST. TECH., *supra* note 160, at 43–52 (discussing reservoir capacity for large–scale geological sequestration and associated risks); *id.* at 56–58 (discussing existing regulatory frameworks in United States for geological sequestration and liability issues).

162. *See China and India Drive Recent Changes in World Coal Trade*, U.S. ENERGY INFO. ADMIN. (Nov 20, 2015), https://www.eia.gov/todayinenergy/detail.cfm?id=23852 [https://perma.cc/H2P3-RLKC] (noting that China and India accounted for 98 percent of the increase in world coal trade from 2008 to 2013); MASS. INST. TECH., *supra* note 160, at 63 (reporting estimate that China and India together are projected to account for more than 68 percent of incremental world demand for coal through 2030).

163. *See* Lackner et al., *supra* note 160, at 146–52 (discussing economics of retrofitting existing coal plants with CO_2 capture technology); MASS. INST. TECH., *supra* note 160, at 28–29 (discussing challenges of retrofitting existing pulverized coal plants with carbon capture technology and concluding that because of significant losses in operating efficiency retrofits seem unlikely).

several utilities and the federal government have already abandoned previous efforts to build IGCC plants (even without any carbon capture technology).[164]

There is, however, an ambitious commercial-scale demonstration IGCC plant currently under construction in Mississippi: the Kemper Integrated Gasification and Combined Cycle Plant (owned by the Mississippi Power Company, a subsidiary of the Southern Company).[165] This facility will include carbon capture and storage technology, with a goal of capturing 65 percent of the carbon dioxide emissions from the plant, giving it an emissions profile similar to that of a combined cycle natural gas plant.[166] The Kemper Plant was initially projected to cost \$2.2 billion, but is now expected to cost \$6.49 billion (and the cost estimates keep rising).[167] In addition to receiving \$270 million in direct financing and another potential \$133 million in investment tax credits from the federal government, the project will also benefit from favorable rate treatment for the initial \$2.3 billion in costs under Mississippi's 2008 Base Load Act.[168] In the absence of new rate increases, the company (and its shareholders) will pay the additional costs.[169] Needless to say,

164. *See* MASS. INST. TECH., *supra* note 160, at 32–39 (discussing IGCC technology and CCS options); Jon Gibbins & Hannah Chalmers, *Carbon Capture and Storage*, 36 ENERGY POL'Y 4317, 4318–19 (2008) (evaluating different CCS technologies and concluding that pre-combustion capture of CO_2 from IGCC plants will produce cheaper low-carbon electricity from coal than the alternatives). *But see* Howard J. Herzog, *Scaling Up Carbon Dioxide Capture and Storage: From Megatons to Gigatons*, 33 ENERGY ECON. 597, 599 (2011) (noting that IGCC cost estimates are "highly uncertain" and that IGCC costs "may have doubled or tripled since 2004").

165. For background on the Kemper project, see *Kemper County Energy Facility: Overview*, MISSISSIPPI POWER, http://www.mississippipower.com/about-energy/plants/kemper-county-energy-facility (last visited Mar.20, 2016). *See also Kemper County IGCC Fact Sheet*, *supra* note 122.

166. *See id.* (noting that the plant will capture 65 percent of total emissions resulting in 3.5 million tons of avoided emissions per year).

167. *Id.* (reporting projected costs of \$6.49 billion as of February 2016).

168. *See* Steven Mufson, *The Coal Plant to End All Coal Plants?*, WASH. POST (May 18, 2014) (discussing history and status of Kemper plant); Alternate Method of Cost Recovery on Certain Base Load Generation, MISS. CODE ANN. § 77-3-101 (2013); Final Order on Remand Granting a Certificate of Public Convenience and Necessity, Authorizing Application of Baseload Act, and Approving Prudent Pre-Construction Costs at 9–10, 20, *In re* Miss. Power Co. (No. 2009-UA-014) (Miss. Pub. Serv. Comm'n 2012) [hereinafter Miss. Pub. Serv. Comm'n] (confirming application of Baseload Act to Kemper Plant and capping rate recovery for costs associated with the Kemper Plant at \$2.4 billion).

169. *See* Miss. Pub. Serv. Comm'n, *supra* note 168 (summarizing regulatory treatment of Kemper plant and capping rate recovery for costs associated with the plant at \$2.4 billion); *see also* Jonas J. Monast & Sarah K. Adair, *Completing the Energy Innovation Cycle: The View From the Public Utility Commission*, 65 HASTINGS L.J. 1345, 1351 (2014) (discussing important role of PUCs in commercial scale demonstration projects for new energy technologies); *id.* at 1374–77 (discussing Mississippi Public Service Commission's involvement in Kemper plant); Mufson, *supra* note 168 (discussing history and status of Kemper plant).

the project has elicited quite a bit of controversy and is the subject of multiple ongoing regulatory proceedings.[170]

Regardless of the individual merits of this project (and others like it), it will clearly have broad social benefits that extend far beyond Mississippi. No one knows how much it will cost to build a "clean coal" plant because no one has ever done it. And no one knows how well such a plant will work because no one has ever operated one at scale. The only way to find out whether this technology will work is to build and operate a commercial scale facility. Thus, rather than view the Kemper project as yet another example of the excesses of rate regulation or the pathologies of capture, it might also be productive to view it as a crucial experiment with a technology that could be a vitally important part of a low-carbon future. This is equally true if the venture in question fails. Although such a failure would surely be expensive and while there are obvious limits to the conclusions that one can draw from a single experiment, a failed experiment such as Kemper could prove quite valuable in terms of the learning experiences it provides. On the one hand, the failure could demonstrate problems and pitfalls to avoid for the next CCS plant. But if the problems and pitfalls are unavoidable, the failure of the Kemper plant to be completed on time and anywhere close to initial budget projections also provides important information about the need to focus on other promising technologies as opposed to CCS in the ongoing effort to decarbonize our electricity system.

In sum, current investments in new nuclear plants and in advanced coal plants with CCS are taking place in traditional cost-of-service states where cost recovery mechanisms provide more certainty with respect to future revenues sufficient to pay financing costs. These innovative forms of cost recovery provide a way of socializing the costs of these investments, thereby allowing utilities to secure financing on more favorable terms. IOUs in these states are leading the effort

170. The ongoing regulatory proceedings before the Mississippi Public Service Commission are primarily in Docket No. 2009-UA-014, 2013-UN-039, 2013-UN-014, and 2013-UN-189. On August 4, 2014, Mississippi Power Co. settled litigation with the Sierra Club, which had been ongoing for four years. In return for an agreement by the Sierra Club to drop all pending legal and regulatory challenges to the Kemper Plant, Mississippi Power agreed to, among other things, retire or convert several other coal-fired power plants, make certain investments in energy efficiency and renewable energy, and drop its opposition to net metering. *See Settlement Agreement Between the Sierra Club and the Mississippi Power Company*, SIERRA CLUB (Aug. 1, 2014), https://mississippi.sierraclub.org/sites/mississippi.sierraclub.org/files/SierraClub-Mississippi PowerSettlement.pdf [https://perma.cc/253S-RDDE]; *see also* Rebecca Smith, *Coal-Fired Power Plant Loses Steam*, WALL STREET J. (May 22, 2015), http://www.wsj.com/articles/coal-fired-power-plant-loses-steam-1432330865 [https://perma.cc/YW8X-5D27] (discussing problems with Kemper plant and noting that South Mississippi Electric Power Association dropped its plan to buy a $600 million, 15 percent stake in the project because of ongoing construction delays).

in partnership with state legislatures and PUCs, while the federal government has played an important role in providing direct subsidies, loan guarantees, and other incentives. Notwithstanding the valid criticisms directed at the way these projects have unfolded, it is also important to recognize the valuable learning opportunities they provide. Looking across the system as a whole and at the three models we have described, this type of innovation seems feasible only in the traditional cost-of-service states—an important contrast to the more downstream focus of hybrid and restructured states on grid modernization, distributed energy resources, and time-variant pricing, as we describe below.

Finally, while it is impossible to know with confidence whether these sorts of experiments would have proceeded under a single, national system of regulation, there is some evidence to suggest that the federal government would have had a difficult time completing these types of experiments under such a system. In fact, the federal government abandoned its own CCS project, the proposed "Future Gen" project in Illinois, in 2015 after killing the project in 2008 and restarting it again in 2010.[171] By making various incentives available for early movers, the federal government has instead allowed specific states (and IOUs) to self select and to decide whether and how they want to pursue these risky investments in advanced low-carbon baseload generation. This kind of experimentation, we argue, is at least partly an unintended outcome of electricity restructuring, which was supposed to lead to a single, unified model but instead resulted in three.

B. Modernizing the Grid

The U.S. power system contains a lot of expensive hardware—more than $1 trillion by some estimates.[172] Big power plants make up a large part of this, but so do the "wires" that constitute the power grid itself. As we described above, the grid can be divided into two major components: high-voltage transmission lines and local distribution systems. Within each of the three major grids or interconnects in the United States (Eastern, Western, and Texas) networks of high voltage transmission lines move bulk power across the system before stepping down

171. *See* Ari Natter, *DOE Suspends $1 Billion in FutureGen Funds, Killing Carbon Capture Demonstration Project*, BNA ENERGY & CLIMATE REP. (Feb. 5, 2015), http://www.bna.com/doe-suspends-billion-n17179922773/ [https://perma.cc/KUF3-EU62] (discussing Department of Energy decision to suspend funding for the FutureGen project, "all but ensuring that the carbon capture and sequestration project in Illinois won't be built").

172. The net asset value of the plant in service for all U.S. electric utilities in 2010 was approximately $1.1 trillion, which includes $765 billion for IOUs, $200 billion for municipal utilities, and $112 billion for rural electric cooperatives. BINZ ET AL., *supra* note 131, at 14.

voltage to transmit electricity to end users through thousands of local distribution systems.[173]

Except in Texas, Alaska, and Hawaii, which have their own transmission grids, FERC regulates use of the high-voltage interstate transmission system (although siting of new transmission lines is left largely to the states). Creating a more robust and expansive bulk transmission system is critical to getting more renewable electricity onto the grid and doing so has proven challenging.[174]

But modernizing the high-voltage transmission system really boils down to finding ways to build more transmission. While there are undoubtedly opportunities to improve the intelligence of the system, we are not faced with the task of trying to turn it into a different type of infrastructure.[175] We mainly just need more of it.[176] FERC's efforts to foster regional approaches to transmission planning and cost allocation, which were recently upheld by the D.C. Circuit, indicate progress in this effort.[177] But there is still a long way to go.

The distribution system, on the other hand, was not designed for the kinds of bidirectional power flows that significant deployment of distributed energy resources such as rooftop solar and storage require.[178] Here, we really do need a

173. *See* U.S. DEP'T OF ENERGY, QUADRENNIAL TECHNOLOGY ASSESSMENT: AN ASSESSMENT OF ENERGY TECHNOLOGIES AND RESEARCH OPPORTUNITIES 53 (2015), http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-03-Grid.pdf [https://perma.cc/LX32-M7W9] (reporting that the U.S. electric power system includes 642,000 miles of high-voltage transmission lines); Amin and Stringer, *supra* note 24, at 400–01 (describing high-voltage bulk transmission grid in North America).

174. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1221, 119 Stat. 594, 946–51 (2005) (establishing process to designate national electricity transmission corridors and providing backstop siting authority for FERC); Piedmont Envtl. Council v. FERC, 558 F.3d 304, 310 (4th Cir. 2009), *cert. denied sub nom.* Edison Elec. Inst. v. Piedmont Envtl. Council, 558 U.S. 1147 (2010).

175. *See, e.g.*, Joskow, *supra* note 28, at 34–37 (discussing need for new investments in monitoring, communication, and control equipment to enhance high voltage transmission systems in the U.S. but noting that the primary need is for more transmission capacity).

176. *Id.*; *see also* Alexandra B. Klass, *The Electric Grid at a Crossroads: A Regional Approach to Siting Transmission Lines*, 48 U.C. DAVIS L. REV. 1895, 1921–25 (2015) (discussing high-voltage transmission system in the United States, need for new transmission lines, and key obstacles to building new lines); Amin & Stringer, *supra* note 24, at 400 (concluding that United States will need 50,000 miles of new high-voltage transmission lines by 2025).

177. *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 (Aug. 11, 2011) (to be codified at 18 C.F.R. pt. 35) (calling for regional transmission planning and cost allocation processes); *see also* S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41 (D.C. Cir. 2014).

178. *See* U.S. DEP'T OF ENERGY, *supra* note 173, at 63–64 (noting "passive" nature of traditional distribution system design and concluding that "[e]nabling customers to become active participants in electric power system operations and energy exchanges will require a fundamental shift in how the distribution system is designed, controlled, and protected"); *id.* at 63 (noting that the distribution system is the most expensive part of the electric delivery system and

different type of infrastructure, and we need it in thousands of local distribution systems across the country. Modernizing this part of the grid will require significant investment in overhauling existing infrastructure and deploying new technologies to enhance the intelligence of the system (the promise of the so-called smart grid), to enable two-way communications between customers and their electricity providers, which is critical for time-variant pricing, and to accommodate the growth and increasing diversity of customer-side generation and storage.[179] One recent estimate put the range of total investment needed in the distribution and consumer segments of the system to achieve a fully functioning "smart grid" at $255 to $385 billion.[180]

Investments in grid modernization, however, are challenging under the traditional cost-of-service model.[181] Given flat electricity demand and the growth of distributed energy resources (not to mention the possibility of grid defection), many utilities are understandably anxious about their ability to recover the substantial, long-term investments needed to modernize the grid through continued sales and the risks that they incur during the period of regulatory lag (that is, the time between rate cases).[182] They need additional certainty regarding cost recovery before they are willing to make such investments, and, in some cases, they need advanced forms of cost recovery rather than having to wait for the investments to be "used and useful" before they can start to recover costs in rates.

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the most difficult to upgrade because there are 6.3 million miles of distribution lines in the United States connecting to 145 million customers).

179. *Id.* at 63–64, 67 (discussing key components of modernized distribution system to enable two-way flows of energy and information); ELEC. POWER RESEARCH INST., THE INTEGRATED GRID: REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES 32 (2014) (discussing needs for modernized distribution system to accommodate growth of DERs).

180. *See* ELEC. POWER RESEARCH INST., ESTIMATING THE COSTS AND BENEFITS OF THE SMART GRID 1–5, tbl.1–2 (2011) (estimating range of total investment in distribution, and consumer segments of a fully functioning grid).

181. *See, e.g.*, MASS. DEP'T OF PUB. UTILS., INVESTIGATION BY THE DEPARTMENT OF PUBLIC UTILITIES ON ITS OWN MOTION INTO MODERNIZATION OF THE ELECTRIC GRID 19 (2014) (noting that "under conventional cost-of-service ratemaking, electric distribution companies may not have the proper incentives for making investments to attain [the Department of Public Utilities'] grid modernization objectives").

182. *See* Philip Hanser & Kai Van Horn, *The Next Evolution of the Distribution Utility*, *in* DISTRIBUTED GENERATION AND ITS IMPLICATIONS FOR THE UTILITY INDUSTRY 231, 232–38 (Fereidoon P. Sioshansi ed., 2014) (discussing revenue challenges facing electric distribution utilities from declining demand associated with improved efficiency, demand response, and growth of distributed generation); William C. Miller et al., *Regulatory Policies for the Transition to the New Business Paradigm*, *in* DISTRIBUTED GENERATION AND ITS IMPLICATIONS FOR THE UTILITY INDUSTRY 321, 321–34 (Fereidoon P. Sioshansi ed., 2014) (discussing investment and cost-recovery challenges facing distribution utilities in current environment of slowing demand and growth of distributed energy resources).

If traditional cost-of-service principles make these grid modernization investments difficult, however, relying on markets to provide sufficient compensation to recover costs is a non-starter. Indeed, even in the fully restructured states, local distribution systems are still managed by distribution utilities and regulated under traditional cost-of-service principles.[183] Because of the natural monopoly characteristics of electricity distribution,[184] no one has proposed opening up that part of the system to competition. Investments in grid modernization are thus not possible under current market structures. As a result, even in fully restructured states, the ratemaking power of PUCs remains quite "traditional" for the distribution system, with PUCs using their ratemaking powers to allow cost recovery for investments in this part of the grid.

To that effect, several hybrid and restructured states are deploying their ratemaking powers to promote ambitious grid modernization efforts. Some of these states are using innovative performance-based rates that provide specific rewards (or penalties) for utilities if they meet (or fail to meet) certain performance benchmarks regarding grid investments.[185] Other states are using advanced cost recovery

183. *See* Stephen Polasky, *Electricity Restructuring and the Environment*, *in* PAINTING THE WHITE HOUSE GREEN: RATIONALIZING ENVIRONMENTAL POLICY INSIDE THE EXECUTIVE OFFICES OF THE PRESIDENT 141, 144 (Randall Lutter & Jason F. Shogren eds., 2004).

184. *See* PAUL L. JOSKOW & RICHARD SCHMALENSEE, MARKETS FOR POWER: AN ANALYSIS OF ELECTRICITY DEREGULATION 59 (1983) (noting that electric power distribution systems are generally considered to have "important natural monopoly characteristics within limited geographic areas").

185. Performance-based rates are structured to allow utilities to capture some or all of the savings that result from improved performance across a chosen metric. *See* Sonia Aggarwal & Edward Burgess, *Performance-Based Models to Address Utility Challenges*, 27 ELECTRICITY J. 48, 50 (2014) ("Under PBR [Performance-based regulation], the utility is rewarded based on its achievement of specific performance targets, providing an opportunity to earn a higher return if the company is able to perform well."); Paul L. Joskow & Richard Schmalensee, *Incentive Regulation for Electric Utilities*, 4 YALE J. ON REG. 1, 1 (1986) (discussing incentive regulation for electric utilities). Over the last several years, targeted performance-based rate programs have been widely deployed in the United States and elsewhere to promote energy efficiency. *See* SONIA AGGARWAL & EDDIE BURGESS, NEW REGULATORY MODELS 12 (2014). Innovative programs include Massachusetts's statewide energy efficiency program and California's recently established Efficiency Savings and Performance Incentives Program. These programs are sometimes included in broader revenue decoupling efforts, which seek to remove the incentive utilities have to increase electricity sales by ensuring that utilities recover their costs even as more consumers participate in demand-side programs that reduce overall utility sales. *See generally* REGULATORY ASSISTANCE PROJECT, REVENUE REGULATION AND DECOUPLING: A GUIDE TO THEORY AND APPLICATION (2011); PAMELA MORGAN, A DECADE OF DECOUPLING FOR US ENERGY UTILITIES: RATE IMPACTS, DESIGNS, AND OBSERVATIONS (2012). *See also* N.Y. DEP'T OF PUB. SERV., CASE 14-M-0101, REFORMING THE ENERGY VISION 49 (2014) (observing that revenue decoupling "provides no positive incentive for utility bill management and exposes the utility and customers to the risk that as some customers reduce demand, the cost of service is borne by the remaining customers").

techniques similar to those used in the case of new nuclear power and CCS discussed in the previous section. In all cases, utilities are getting additional protections and incentives regarding long-term investments necessary for grid modernization.

Illinois (a restructured state), for example, has been a leader in using performance-based rates to encourage large investments in grid modernization. The state's 2011 Energy Infrastructure Modernization Act[186] allows the state's two major distribution utilities to adopt a system of performance-based formula rates for their distribution systems if they agree to make substantial investments in grid infrastructure and achieve various other performance objectives.[187] Under the program, the state's largest utility, ComEd, which serves northern Illinois and the Chicago area, is investing $2.6 billion over ten years to upgrade and modernize its transmission and distribution systems and deploy various smart grid technologies.[188] The performance-based formula in the legislation allows ComEd to recover its actual costs plus a fixed return on equity as long as it continues to meet various performance benchmarks.[189] It also includes specific provisions to protect customers against excessive rate increases and penalties in cases where the utility does not meet certain performance benchmarks.[190]

Massachusetts (another restructured state) has taken a different approach to grid modernization, providing for advanced cost recovery and up-front prudence determinations in a manner similar to what Georgia, South Carolina, Mississippi and other cost-of-service states are doing with respect to utility investments in new nuclear and CCS plants. In a recent order issued on its own motion, the Massachusetts Department of Public Utilities (DPU) set forth an ambitious

186. ILL. COMP. STAT. ANN. § 16-108.5 (2015).

187. The key provisions of the legislation are codified at ILL. COMP. STAT. ANN. § 16-108.5 to 16-108.8 (2015). Section 16-108.5 contains the provisions distribution system investments and performance-based formula rates.

188. *See id.* at § 16-108.5 (authorizing a ten-year $2.6 billion investment plan for ComEd, which the statute identifies as a "participating utility" serving more than one million Illinois customers). The same provision also authorizes $605 million in investments by the state's smaller distribution utility, Ameren). *See also* Louis Harris, *Smart Grid and AMI: Illinois Pioneers a New Approach*, 26 ELECTRICITY J. 66, 69–71 (2013) (describing features of Illinois program, including ConEd and Ameren investments).

189. The formula rate allows the utility to recover the actual costs of the investments, includes a return-on-equity equal to 6 percent plus the average yield of 30-year U.S. Treasury bonds for the applicable year, and provides for incentive compensation tied to certain operational metrics. *See* ILL. COMP. STAT. ANN. § 16-108.5(c) (outlining provisions of the performance-based formula rate); *id.* at § 16-108.5(f) (outlining performance metrics).

190. *Id.* at § 16-108.5(f), (f-5), (g) (outlining financial penalties as applied to utility performance metrics and customer protections against rate increases).

program of grid modernization for the state's distribution utilities.[191] The Order requires each distribution utility to submit a ten-year grid modernization plan that will reduce outages, optimize demand, integrate distributed resources, and improve workforce and asset management.[192] Each utility must also propose a more specific, five-year, short-term investment plan (STIP) that outlines the business case for the utility's capital investments in grid modernization.[193] The Order identifies performance metrics, but these are to be used (at least initially) to track progress rather than to serve as a basis for incentives or penalties. Investments elaborated in the short-term investment plan are eligible for "pre-authorization" from the DPU, which means that the DPU "will not revisit in later filings whether the company should have proceeded with these investments."[194] This provides, in effect, an ex ante prudency determination for the proposed investments, although the DPU does reserve the right to evaluate prudency in the implementation of the investments.[195] Finally, the Order provides targeted cost recovery through a capital tracker mechanism for investments in advanced metering functionality and incremental capital investments in grid modernization.[196] This allows the utilities to recover costs in a more timely manner (as they make them) rather than having to wait for the results of the next rate case.[197]

As in Illinois, much of Massachusetts's grid modernization effort is tied to advanced metering functionality, which the DPU describes "as the basic technology platform for grid modernization."[198] In fact, as discussed in more detail below, Massachusetts has paired its grid modernization effort with a companion order on time-variant rates. The goal of grid modernization, in other words, is largely (but not exclusively) tied to the effort to provide more robust price signals to electricity consumers as a means of achieving reductions in peak load. This is particularly important in Massachusetts and neighboring states given that one-third of the installed electric generating capacity in New England is

191. *See* MASS. DEP'T OF PUB. UTILS., *supra* note 181.
192. *Id.* at 2.
193. *Id.* at 3.
194. *Id.* at 3–4.
195. *Id.* at 19 ("Department pre-authorization means that the Department will not revisit whether the company should have proceeded with these investments. The Department will, however, review the prudency of the company's implementation of these investments.").
196. *Id.* at 19–20, 22–25. Targeted cost recovery for incremental capital investments in the grid is only available if the utility is also investing in advanced metering functionality. *Id.*
197. *Id.* at 22. Investments in advanced metering also need not be "used and useful" by the year during which cost recovery is sought. *Id.* at 25.
198. *Id.* at 14.

used to meet peak demand for only 10 percent of the year—that is, one-third of the generation in New England sits idle for 90 percent of the year.[199]

Other states are launching their own grid modernization efforts, following in the footsteps of leaders such as Illinois and Massachusetts. Maryland and Pennsylvania, for example, have adopted special cost recovery mechanisms for smart meters.[200] New York and California are also addressing various aspects of grid modernization in their broader efforts on distributed energy resources (as we describe below). And Texas, which has the largest and most competitive electricity market in the U.S., has pioneered the use and integration of its advanced metering infrastructure to make data available to third parties and enhance new services offerings to customers.[201]

In all of these cases, grid infrastructure investments have been subject to various forms of advanced cost recovery or performance-based rates. These efforts to modernize the grid recognize the inability of both current market structures and traditional cost-of-service regulation to provide sufficient incentives to make the necessary investments. By enabling these investments, these states are seeking to facilitate the broad social benefits that come with grid modernization and the fundamental role that the distribution system must play as a platform for the continued growth of distributed energy resources and the move to time-variant rates. Here too, the federal government has played a largely catalytic role by providing $4.4 billion in funding for smart grid demonstration and technology deployment projects, including significant support for advanced metering infrastructure, and by continuing to fund research on grid modernization.[202] It is, of course, possible that these grid infrastructure investments would also proceed

199. *Id.* at 10–11.
200. *See* GRIDWISE ALL., 2014 GRID MODERNIZATION INDEX (GMI) 10–11 (2014), https://www.illinois.gov/dceo/Documents/GWA_14_GridModernizationIndex_11_17_14Final.pdf (summarizing grid modernization efforts in leading states).
201. *See* Amanda Levin, *Customer Incentives and Potential Energy Savings in Retail Electric Markets: A Texas Case Study*, 28 ELECTRICITY J. 51, 58–62 (2015) (discussing smart meter deployment in Texas and development of new statewide portal, SmartMeterTexas, to make data available to retail electricity providers and third parties). *But see id.* at 59 (noting that to date customer use of the new SmartMeterTexas portal "has been dismal" with less than 0.5 percent of customers using the service).
202. *See* FED. ENERGY REGULATORY COMM'N, ASSESSMENT OF DEMAND RESPONSE & ADVANCE METERING: STAFF REPORT 5 (Dec. 2015) (reporting that between 2009 and 2015 the Department of Energy and the electric industry invested more than $7.9 billion "to accelerate deployment of smart grid technologies and systems, strengthen cybersecurity, improve interoperability, and collect data on smart grid operations, benefits, and utility impacts"); *DOE Announces $220 Million in Grid Modernization Funding*, U.S. DEP'T OF ENERGY (Jan. 14, 2016), http://www.energy.gov/articles/doe-announces-220-million-grid-modernization-funding [https://perma.cc/9KB7-B6ND].

under a single, national model of regulation, but we likely would not see the diversity of approaches—performance incentives, creative cost recovery policies, and so forth—that we see now across the different states.

C. Promoting Distributed Energy Resources

One of the promises of grid modernization is its ability to serve as a platform for continued growth of distributed energy resources (DERs) such as rooftop solar, storage, and electric vehicles. Over the last several years, the United States has witnessed explosive growth in distributed generation, primarily in the form of rooftop solar.[203] Customer-side storage and electric vehicles have not seen widespread deployment, but these are starting to attract much more attention from regulators, utilities, and third parties.[204]

Along with tax credits and new financing arrangements, rate design has played a fundamental role in stimulating the growth of distributed generation.[205] Net metering has been the primary tool, with forty-four states and the District of Columbia adopting some form of net metering program.[206] As participation in these net metering programs has grown, however, concerns have been raised

203. *See* U.S. DEP'T OF ENERGY, REVOLUTION NOW: THE FUTURE ARRIVES FOR FOUR CLEAN ENERGY TECHNOLOGIES 4 (2013) ("In 2012, rooftop solar panels cost about 1% of what they did 35 years ago, and since 2008, total U.S. solar PV deployment has jumped by about 10 times—from about 735 megawatts to over 7200 megawatts."); *Solar Market Insight Report 2014 Q4*, SOLAR ENERGY INDUS. ASS'N, http://www.seia.org/research-resources/solar-market-insight-report-2014-q4 [https://perma.cc/4MJ4-FLFJ] (last visited Mar. 20, 2016) (noting that residential solar in the United States grew at annual rates of over 50 percent in 2012, 2013, and 2014).

204. *See* GARRETT FITZGERALD ET AL., THE ECONOMICS OF BATTERY ENERGY STORAGE: HOW MULTI-USE, CUSTOMER-SITED BATTERIES DELIVER THE MOST SERVICES AND VALUE TO CUSTOMERS AND THE GRID 22–34 (2015) (discussing value of multiple services provided to the electric power grid by customer-sited storage). Utility interest in electric vehicles is growing in several states, notably California. In January 2016, the California Public Utilities Commission approved a first pilot phase of Southern California Edison's Charge Ready Program, allowing the utility to install 1500 electric vehicle charging stations in its territory. *See* Decision Regarding Southern California Edison Company's Application For Charge Ready And Market Education Programs, Decision No. 16-01-023, (Cal. Pub. Utils. Comm'n Jan. 14, 2016). For a more general discussion, see ADAM LANGTON & NOEL CRISOSTOMO, VEHICLE-GRID INTEGRATION: A VISION FOR ZERO-EMISSION TRANSPORTATION INTERCONNECTED THROUGHOUT CALIFORNIA'S ELECTRICITY SYSTEM (2013), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M080/K775/80775679.pdf [https://perma.cc/7PWV-5F67] (discussing opportunities for electric vehicles as distributed energy resources in California).

205. *See generally* NAIM R. DARGHOUTH ET AL., NET METERING AND MARKET FEEDBACK LOOPS (2015) (noting importance of net metering and rate design in supporting the growth of distributed solar PV).

206. *See* DSIRE, NET METERING (Mar. 2015), http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/04/Net-Metering-Policies.pdf [https://perma.cc/8HJE-R67Y].

about possible cross-subsidies and their effects on utility business models.[207] A number of states have thus begun to experiment with new distributed generation tariffs that are designed to, on the one hand, reward distributed generators that produce their own electricity while on the other hand ensure that distributed generators pay for the grid services they use.

Net metering programs to support distributed generation can be traced back to PURPA and the efforts of several states to provide alternatives for small customer-owned generation.[208] As previously discussed, PURPA created a special program for QFs—small renewables and co-generation facilities—giving them the right to sell power to utilities for a fixed time at the utility's avoided cost.[209] In the absence of an alternative, small customer-owned generation would be treated as QFs under PURPA, which would require customers to install two meters (one for the retail power they used and one for the excess power they generated and sold back to the utility at avoided cost) and to enter into simultaneous purchase and sale agreements with the utilities.[210] Net metering sought to avoid this complexity and provide additional incentives for customer-owned generation by using a single meter that would literally spin backwards during times of excess power generation and, in doing so, credit the power generated in excess of the customer's use at the retail rate rather than at the lower avoided-cost rate required under PURPA.[211]

PUCs established these early net metering programs with the goal of creating incentives for customer-owned renewable generation. In 1981, for example, the Arizona Corporation Commission (the equivalent of their PUC) allowed net metering for small customer generation of 100 kilowatts or less.[212] The Massachusetts PUC established a similar program the following year.[213]

207. *See, e.g.*, ENERGY DIV., CAL. PUB. UTILS. COMM'N, CALIFORNIA NET ENERGY METERING (NEM) DRAFT COST-EFFECTIVENESS EVALUATION 30–38 (2013) (estimating systems costs borne by non-DG customers); CARL LINVILL ET AL., DESIGNING DISTRIBUTED GENERATION TARIFFS WELL 29–30 (2013). *But see* ROCKY MOUNTAIN INST., NET ENERGY METERING, ZERO NET ENERGY AND THE DISTRIBUTED ENERGY RESOURCE FUTURE 36, 40 (2012) (noting that many questions about the net effects of distributed energy resources remain to be answered and that "[u]nder current volumetric rate structures, net metering does not accurately recover the costs of a customer's use of the grid network and, simultaneously, it may not be compensating the customer for the value of the power they are providing").

208. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (1978).

209. *Id.* § 210.

210. *See* YIH-HUEI WAN, NET METERING PROGRAMS 1 (1996) (discussing the history of and rationale for net metering programs).

211. *Id.*

212 *See id.*

213. *See id.*

In 1983, Minnesota became the first state to enact a net metering statute. Since that time nearly all states have established (by statute or regulation) some form of net metering program.[214] While the details vary, the programs are similar in their overall design and function. In essence, they allow owners of distributed generation (DG) to get the full retail price for excess power that is fed back to the grid.[215] Net metering programs work in both regulated states and in states with retail choice. In states allowing retail choice, there are some differences regarding which entity is responsible for the net metering program: the DG customer's retail electricity provider or the distribution company, which is usually the incumbent utility.[216]

The great advantage of net metering has always been its simplicity. A single meter, with a single rate, provides a simple approach to crediting customer generation.[217] After the programs are established, moreover, there is no need for any regulatory interaction or supervision.[218] The programs do not require any public funding.[219] And they have been structured in a manner that allows the states to avoid encroaching on FERC jurisdiction.[220] It is therefore no surprise that net metering has been adopted so widely in the United States.

As long as the overall penetration of DG remains low, net metering programs have little impact on a utility's bottom line. In recent years, however, certain forms of DG, particularly rooftop solar, have experienced dramatic growth, driven by rapidly declining costs for solar photovoltaic (PV) modules, the

214. *See* L. BIRD ET AL., REGULATORY CONSIDERATIONS ASSOCIATED WITH THE EXPANDED ADOPTION OF DISTRIBUTED SOLAR 29–30 (2013). Nearly all states have adopted some form of net metering tariff. *See* DSIRE, *supra* note 206.

215. Jocelyn Durkay, *Net Metering: Policy Overview and State Legislative Updates*, NAT'L CONF. ST. LEGISLATURES, http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx [https://perma.cc/4J9F-6L7P] (last updated Dec. 18, 2014) (describing net metering policies across the U.S.).

216. *See State Electric Retail Choice Programs Are Popular With Commercial and Industrial Customers*, *supra* note 87.

217. WAN, *supra* note 210, at 4.

218. *Id.*

219. *Id.*

220. The net metering transaction could be characterized as a wholesale sale of electricity. By structuring it as a "credit" for excess generation, however, state net metering programs have avoided triggering federal jurisdiction. FERC has blessed this in the case of individual customer generators and in the case of third parties (such as third party solar leasing companies). *See* MidAmerican Energy Co., 94 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,340 (2001) (finding no sale when an individual customer installs generation on-site and accounts for its excess generation through netting); Sun Edison LLC, 129 Fed. Energy Reg. Comm'n (CCH) ¶ 61,146 (2009) (finding no sale when third party owns customer-sited generation and deals with excess through netting). For a thoughtful discussion of the jurisdictional issues raised by net metering and an argument against extending FERC jurisdiction to cover net metering, see Jim Rossi, *Federalism and the Net Metering Alternative*, 29 ELECTRICITY J. 13 (2016).

availability of third-party solar leases, and various tax credit and other incentives, including, most prominently, net metering.[221]

Some utilities, PUCs, and ratepayer advocates have responded by raising concerns about the effect of such growth on utility business models and the potential cross-subsidies embedded in net metering programs.[222] The basic argument is that DG customers, even though they are benefitting from their connection to the grid, are not paying their fair share of grid services, leaving non-DG customers (who are often lower-income customers) to pay a larger share of these systems costs.[223] While it is surely the case that non-DG customers stand to benefit from the growth in DG to the extent that it reduces the need for utility investments in new generation, transmission, and distribution, and to the extent that it promotes a more reliable and resilient grid, several recent analyses have raised concerns about the implications of DG growth for non-DG customers who are left paying for a larger share of the utility's fixed costs.[224] As long as DG accounts for a very small portion of a utility's customer base, this is not much of an issue. As participation in net metering grows, however, the cross-subsidy issues become more important and contentious.[225]

221. *See* U.S. DEP'T OF ENERGY, *supra* note 203 ("In 2012, rooftop solar panels cost about 1% of what they did 35 years ago, and since 2008, total U.S. solar PV deployment has jumped by about 10 times—from about 735 megawatts to over 7200 megawatts."); Easan Drury et al., *The Transformation of Southern California's Residential Photovoltaics Market Through Third-Party Ownership*, 42 ENERGY POL'Y 681, 689 (2012) (observing that "[t]hird-party owned residential PV systems are rapidly gaining market share in the United States in the regions where they are allowed to enter the market" and concluding that "[p]olicies that enable third-party PV products to enter new markets . . . represent strong opportunities for stimulating PV demand in concert with traditional incentives that reduce system costs or increase revenues").

222. *See* EDISON ELEC. INST., DISRUPTIVE CHALLENGES: FINANCIAL IMPLICATIONS AND STRATEGIC RESPONSES TO A CHANGING RETAIL ELECTRIC BUSINESS 11, 13 (2013); Diane Cardwell, *On Rooftops, a Rival for Utilities*, N.Y. TIMES, July 27, 2013, at B1; Navigant Research, *Distributed Generation Poses Existential Threat to Utilities*, FORBES (Aug. 26, 2013, 1:46 PM), http://www.forbes.com/sites/pikeresearch/2013/08/26/distributed-generation-poses-existential-threat-to-utilities.

223. *See, e.g*, LINVILL ET AL., *supra* note 207, at 6; N.Y. DEP'T OF PUB. SERV., *supra* note 185, at 54.

224. *See* ENERGY DIV., CAL. PUB. UTILS. COMM'N, *supra* note 207 (estimating systems costs borne by non-DG customers); LINVILL ET AL., *supra* note 207, at 29–30. *But see* ROCKY MOUNTAIN INST., *supra* note 207 (noting that many questions about the net effects of distributed energy resources remain to be answered and that "[u]nder current volumetric rate structures, net metering does not accurately recover the costs of a customer's use of the grid network and, simultaneously, it may not be compensating the customer for the value of the power they are providing").

225. In California, for example, a recent study performed on behalf of the California Public Utilities Commission (CPUC) estimated that the total costs of distributed generation (DG) with full participation in the state's net metering program through 2020 would be $1.1 billion, or about 3.5 percent of IOU revenues. *See* ENERGY DIV., CAL. PUB. UTILS. COMM'N, *supra* note 207, at 7 tbl.2.

These issues have led a number of states to reexamine their net metering programs and to consider alternative tariff designs.[226] Some of these efforts have been initiated by the legislature as part of a broader program of rate reform. Others are being led by PUCs and their staffs, either as part of a broader rate reform effort or in specific cases regarding individual utilities. Still others are emerging out of interactions between the PUC and state energy offices, which have been established in some states by the governor to play a policy coordination role on energy.

In California, a hybrid state, the legislature has taken the lead on policy but largely in response to efforts by the California Public Utilities Commission (CPUC) to understand and manage the growth of DERs in the state. New legislation enacted in late 2013, for example, requires the CPUC to develop a new tariff for DG customers for offer in 2017 and gives the CPUC new authority to approve standby charges assessed to DG customers.[227] The law also requires that the new tariff balance benefits and costs for all customers and protect against cross-subsidies.[228] Pursuant to this statutory mandate, the CPUC adopted (by a 3-2 vote) a new Net Energy Metering Tariff in January 2016.[229] The new tariff preserves the basic elements of net metering, but it also requires net metering customers to switch to time-of-use rates, which will change the value of net metering credits that they receive, and it imposes new interconnection fees and adds monthly fixed charges for residential DG customers.[230]

In addition to its work on net metering, the CPUC has been exploring a broader range of issues regarding distributed energy resources, smart grid, and distribution system planning. Currently, the CPUC has at least eight open proceedings on topics related to the ongoing effort to increase the amount of DERs in the state.[231] With a 2020 mandate of six hundred megawatts of storage for each of the state's three IOUs, rapid growth of distributed generation, and goals of 5 percent demand response and 1.5 million electric vehicles over the next ten years, California is once again embarking on a dramatic overhaul of its electricity

226. For a thorough and thoughtful analysis of the cost and benefit considerations that should be included in designing such tariffs, see Richard L. Revesz & Burcin Urcel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering* (N.Y.U. Sch. of Law Pub. Law & Legal Theory Research Series, Working Paper No. 16-09, 2016), http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2734911.
227. A.B. 327, 2013–2014 Reg. Sess. (Cal. 2013).
228. *Id.* at §§ 11(b)(3)–(4).
229. *See* Decision Adopting Successor to Net Energy Metering Tariff, Decision No. 16-01-044 (Cal. Pub. Utils. Comm'n Jan. 28, 2016).
230. *Id.*
231. The key rulemaking is the Distribution Resource Planning Docket No. 14-08-13.

sector. The overall goal is "to create a distribution grid that is 'plug and play' for DERs."[232]

In all of this, policy innovation is emerging out of the interactions between the CPUC and the legislature rather than from one body or the other. This iterative relationship between the PUC and the legislature has proven to be highly productive. As a hybrid state, California is also seeking to harness the power of its IOUs in advancing DERs, directing them to plan for and incorporate DERs in their distribution planning exercises and including the costs of infrastructure, such as electric vehicle charging stations, and new DERs, such as storage, in their rates.[233]

New York (a fully restructured state) has been pursuing a similarly broad agenda of rate reform, but one that has been driven in large part by the staff of the New York Department of Public Service with little involvement to date by the legislature.[234] As in California, net metering reform is being considered in the context of a broader set of issues regarding how to create and govern a distribution system that can accommodate multi-directional power flows and large amounts of DERs. In contrast to California, however, the goal in New York is to create ("animate") new markets for DERs and transform existing distribution utilities into what the commission is calling "distribution service platform providers."[235] Under this model, the new distribution platform provider would act more as a neutral system operator and market administrator for a "transactive" grid that would enable retail electricity providers, third party vendors, and individual owners of distributed energy resources to interact directly in the market.[236] Needless to say, the ratemaking and rate design implications of this new model are substantial. Proposals for specific rate reforms to implement the new model were released in July 2015 and are the subject of ongoing discussion.[237]

232. CAL. PUB. UTILS. COMM'N, ASSIGNED COMMISSIONER'S RULING ON GUIDANCE FOR PUBLIC UTILITIES CODE SECTION 769—DISTRIBUTION RESOURCE PLANNING 3 (2014).
233. CAL. PUB. UTILS. COMM'N, ORDER INSTITUTING RULEMAKING—DISTRIBUTION RESOURCE PLANNING 4–6 (2014).
234. *See* N.Y. DEP'T OF PUB. SERV. COMM'N, CASE 14-M-0101, REFORMING THE ENERGY VISION: ORDER ADOPTING POLICY FRAMEWORK AND IMPLEMENTATION PLAN (2015).
235. *See id.* at 31–61.
236. *Id.*
237. *See* N.Y. DEP'T OF PUB. SERV., STAFF WHITE PAPER ON RATEMAKING AND UTILITY BUSINESS MODELS, CASE 14-M-0101, PROCEEDING ON MOTION OF THE COMMISSION IN REGARD TO REFORMING THE ENERGY VISION (2015). Among other things, the White Paper discusses modifications to distribution utility revenue models to encourage utilities to enable increased DER penetration (38–44), the use of performance-based rates (51–66), and rate design and cross-subsidy issues involved in different approaches to DER compensation (73–107).

While New York and California are engaged in the most ambitious exercises to overhaul their distribution systems and find new ways to compensate and enable DERs, other states are engaged in more discrete efforts to reform their net metering programs and adopt new rate designs for DG. Arizona (a traditional state), for example, is addressing the net metering issue in the narrow context of a request from the state's largest IOU.[238] Instead of embracing a broader approach to DERs, the Arizona Commission has adopted a simple solution that leaves the net metering program in place but seeks to offset it with a charge for the grid services that DG customers receive.[239] Interestingly, the Arizona Commission has also allowed the state's two IOUs to experiment with limited ownership of rooftop solar for low-income customers.[240] This is viewed as a possible pathway to rate-base treatment for rooftop solar owned and operated by IOUs, which could have important implications for solar in Arizona and beyond.[241]

Minnesota (a hybrid state) has taken another approach to distributed solar, focusing specifically on what it calls the "value of solar" in redesigning its net metering program. As in California, the legislature has taken the lead, enacting a new law in 2013 that allows the state's IOUs to apply to the PUC for a "value of solar" tariff as an alternative to net metering.[242] Under the new law, the state Department of Commerce has developed a methodology for calculating the rates and charges under the value of solar tariff that separates the various components of solar DG, including delivered energy; avoided generation, transmission, and

238. In July 2013, the Arizona Public Service Company (APS) filed an application with the state's Corporation Commission requesting a "cost shift solution" (that is, a new fee for DG customers) to address the $18 million cross-subsidy which the company claims is being provided to DG customers under the state's net metering policy. *See In re* Application of Arizona Public Service Co. for Approval of Net Metering Cost Shift Solution at 9, No. E-01345A-13-0248 (July 12, 2013).

239. In November 2013, the Arizona Corporation Commission voted (3-2) to approve a new fixed charge (seventy cents per kilowatt of installed DG capacity per month) on new solar DG customers starting in 2014. *See* Decision No. 74202 at 29–31, *In re* Application of Arizona Public Service Co. for Approval of Net Metering Cost Shift Solution, No. E-01345A-13-0248 (Dec. 3, 2013).

240. In December 2014, the Commission voted "no objection" to APS's $28.5 million proposal to own ten megawatts of residential solar systems. Customers that rent their roofs to the utility will put no money down and receive a $30 credit on their bill each month for up to twenty years. The program is limited to ratepayers with low credit scores. APS will need to show that the investment is prudent before seeking to recover expenses in its next rate case. *See In re* Arizona Public Service Company for Approval of its 2015 Renewable Energy Standard Implementation Plan for Reset of Renewable Energy Adjustor at 4–7, No. E-01345A-14-0250 (Dec. 18–19, 2014).

241. *See, e.g.*, Lon Huber, *Why Utility Ownership of Rooftop Solar Should Be Explored*, UTILITYDIVE (July 21, 2015), http://www.utilitydive.com/news/why-utility-ownership-of-rooftop-solar-should-be-explored/402645 [https://perma.cc/F7AM-92UG] (discussing Arizona example and implications for rate-base treatment of rooftop solar and DERs generally).

242. *See* MINN. STAT. § 216B.164, subdiv. 10 (2013).

distribution; and avoided environmental costs.[243] The PUC approved the value of solar methodology in April 2014.[244]

Minnesota's effort is a more ambitious and complex undertaking than the simple systems charge that Arizona enacted. In essence, Minnesota is seeking to unbundle the existing structure of volumetric rates and allow various actors to pay for the different kinds of grid services that they use (and to receive compensation for the services they provide).[245] In all of this, however, the PUC is acting more as implementer rather than policy innovator, taking its direction from the legislature, a reflection of the fact that the Minnesota PUC has limited staff.[246]

New rate reform efforts to promote DERs are also underway in several other states, including Colorado, Georgia, Hawaii, Kansas, Nevada, South Carolina, and Vermont.[247] While some of these states are taking a relatively simple approach that typically involves some sort of grid services charge for DG customers (like the Arizona approach mentioned above), others have embarked on ambitious efforts to develop new tariff structures for DG.[248] And some, such as Nevada, have adopted aggressive net metering reforms that will sharply limit the growth of rooftop solar.[249] The politics of all of this have been quite intense as

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243. *See* DIV. OF ENERGY RES., MINN. DEP'T OF COMMERCE, MINNESOTA VALUE OF SOLAR: METHODOLOGY (2014).
244. *See* MINN. PUB. UTILS. COMM'N, ORDER APPROVING DISTRIBUTED SOLAR VALUE METHODOLOGY (2014).
245. *See* MIKE TAYLOR ET AL., VALUE OF SOLAR: PROGRAM DESIGN AND IMPLEMENTATION CONSIDERATIONS 8–11 (2015) (discussing key components of value-of-solar methodology for compensating rooftop solar).
246. *See Regulatory Commissions*, *supra* note 46 (reporting that the Minnesota PUC has a staff of forty-two).
247. *See, e.g.*, Mark Jaffe, *Battle Over Rooftop Solar Heads to Public Utilities Commission*, DENVER POST (Jan. 12, 2014, 12:01 AM) http://www.denverpost.com/business/ci_24889841/battle-over-rooftop-solar-heads-public-utilities-commission [http://perma.cc/XV2A-9QG4] (discussing fight over net metering in Colorado); Edward Humes, *Throwing Shade: How the Nation's Investor-Owned Utilities Are Moving to Blot out the Solar Revolution*, SIERRA (May/June 2014), http://content.sierraclub.org/new/sierra/2014-3-may-june/feature/throwing-shade [http://perma.cc/NY8D-574J] (describing fights over net metering in various states).
248. South Carolina, for example, has recently enacted a new Distributed Energy Resources Program Act that commits the state to a value of solar proceeding. *See* Distributed Energy Resources Program Act, S.B. 1189, 2013 S.C. Gen. Assemb., 120th Sess. (S.C. 2014).
249. In December 2015, the Public Utilities Commission of Nevada unanimously approved a new solar net metering policy that decreases the rate paid to rooftop solar customers for the power they export to the grid from the retail electricity rate to the wholesale rate. The change applies retroactively to all solar customers. In February 2016, the Commission issued a modified final order in response to various requests for reconsideration that left the basic elements of the December 2015 order intact. *See* Pub. Utils. Comm'n of Nev., Order on Application of Nevada Power Company d/b/a NV Energy for Approval of Cost-of-Service Study and Net Metering Tariffs, No 15-07041 (Feb. 17, 2016), http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/9690.pdf.

DG advocates argue that utilities, captured regulators, and conventional energy producers are trying to stifle the development of rooftop solar and preserve the status quo while some utilities, regulators, and consumer advocates point to the potential negative effects of widespread net metering on poorer customers and the threats to utility business models.[250] Irrespective of how these particular battles play out, however, it seems that there are (again) certain advantages to the diversity of current efforts to accommodate the growth of DG and the emergence of a more distributed electricity system.

As for efforts to promote other DERs such as storage and electric vehicles, California, as noted, has adopted an ambitious storage mandate for its IOUs and is also allowing its IOUs to include some of the costs of electric vehicle charging stations in rates.[251] And in Texas, the state's largest distribution utility, Oncor Energy, has proposed a $5.2 billion investment in storage—enough to handle one-eighth of the state's power load on an average winter's day.[252] No regulatory proceedings have been initiated on the proposal to date and there are some obstacles under current law, but if this moves forward it would be the largest storage experiment in the world.[253]

In general, innovative rate designs to promote DERs are occurring mainly in restructured and hybrid states. But a number of traditional cost-of-service states are engaged in efforts to reform net metering and, in some cases, to develop new tariffs to promote DERs, all with varying degrees of ambition. The more complex efforts are, not surprisingly, being undertaken in states with larger, more professional PUCs such as California and New York. Many states seem to

250. *See, e.g.*, Charles J. Cicchetti & Jon Wellinghoff, *Solar Battle Lines: The Fight Over Customer Rooftops, Grid Funding, and Net Metering*, PUB. UTIL. FORT. (Dec. 2015) (discussing ongoing battles over rooftop solar); Humes, *supra* note 247 (describing fights over net metering in various states); Cardwell, *supra* note 222 (discussing challenges to utility business models from rooftop solar); Navigant Research, *supra* note 222 ("To the list of industries at risk of complete obsolescence—which at the moment includes daily newspapers, government postal services, and men-only barbershops, among others—you can add U.S. power utilities.").

251. *See generally Zero-Emission Vehicles Proceedings*, CAL. PUB. UTILS. COMM'N, http://www.cpuc.ca.gov/General.aspx?id=5597 [https://perma.cc/FD9R-5QGW] (last visited Mar. 21, 2016) (summarizing various CPUC proceedings and initiatives for electric vehicles). *See also* CPUC Decision Approving Phase 1 of SCE's Charge Ready Program, *supra* note 204.

252. James Osborne, *Oncor's Backup Plan for Texas Power Gives Jolt to Energy Storage Industry*, DALL. MORNING NEWS (Dec. 29, 2014, 11:00 PM), http://www.dallasnews.com/business/energy/20141229-oncors-plan-to-backup-texas-power-gives-jolt-to-energy-storage-industry.ece [http://perma.cc/E796-VDL7]. The company is proposing five gigawatts of storage, almost four times the California 2020 mandate of 1.3 gigawatts. *See id.*

253. Under the state's restructuring law, Oncor (a wires company) is prohibited from selling electricity in the wholesale market. *See* Jim Malewitz, *State Law Could Short-Circuit Battery Breakthrough*, TEX. TRIB. (Dec. 15, 2014), http://www.texastribune.org/2014/12/15/state-law-could-short-circuit-battery-breakthrough [http://perma.cc/W3YL-QAVS].

be taking a wait-and-see approach as various innovators test out new ideas and approaches. But in all cases, there is a general recognition that DERs will play an increasingly important role in the electricity mix going forward and that the traditional model of bundled, volumetric rates cannot effectively accommodate these resources.

For its part, the federal government has played an important role in nudging and guiding various efforts. From early support for new rate designs to support DG to specific decisions by FERC to forego any assertion of jurisdiction over net metering and more recent support for accelerated deployment of electric vehicles and storage, federal interventions have facilitated experimentation by various states operating under all three models.

D. Time-Variant Pricing

While grid modernization carries with it significant promise, advanced metering technologies will have little effect in the absence of rate reform. With widespread installation of smart meters, time-variant pricing could provide a mechanism to shift consumer electricity use to times of lower demand. This shift can reduce overall energy use, lower carbon emissions, and even help integrate intermittent energy resources like solar and wind onto the grid.[254]

Though some form of time-variant pricing has existed for decades—first introduced as policy by Alfred Kahn during his tenure as Chairman of the New York Public Service Commission in the 1970s[255]—PUCs have largely steered away from broad adoption of time-variant rates for residential and small commercial consumers. Penetration of time-variant pricing for large commercial and industrial customers is higher across the country.[256] But rate reform advocates and a handful of PUCs have begun to focus on residential rates, suggesting that we may be seeing the beginning of a dramatic shift in the way such rates are set.

The idea of time-variant rates is a straightforward one: Customer retail rates should increase or decrease to reflect changes in the cost of generating electricity

254. *See* MASS. INST. TECH., *supra* note 21, at 150.

255. *See* ANDERSON, *supra* note 60, at 96, 110; *see also* ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS 63–122 (1970) (providing detailed discussion of the theory and application of marginal cost pricing); Alfred E. Kahn, *Applications of Economics to an Imperfect World*, 69 AM. ECON. REV. 1, 2 (1979) ("One of my proudest accomplishments [as Chairman of the New York Public Service Commission] . . . was the progress we made in requiring the electric and telephone companies in New York to introduce marginal cost-related prices."); Paul L. Joskow & Catherine D. Wolfram, *Dynamic Pricing of Electricity*, 102 AM. ECON. REV. 381, 381–83 (2012) (discussing Kahn's work on marginal cost pricing and status of efforts to expand dynamic pricing).

256. *See* MASS. INST. TECH., *supra* note 21, at 161–62.

over the course of the day (and year).[257] At times of peak demand, if rates are dynamically priced customers can decrease their usage to avoid paying the highest prices for electricity, which can be five to ten times more expensive than non-peak prices in the wholesale market.[258] Some of this decrease may lower overall energy usage entirely (using less air conditioning on especially hot days and less heat on especially cold ones) while some of the decline in peak use may simply shift energy consumption to non-peak times (using the dishwasher at night rather than during the day when demand tends to peak, at least during the summer).

Time-variant pricing has a number of aims. Historically, one of the most important goals has been to avoid system overload and blackouts during times of peak demand.[259] If retail electricity prices are allowed to rise (sometimes dramatically) during peak periods when wholesale generating costs are highest, then price-sensitive consumers will curtail their usage.[260] But time-variant pricing can be used for other purposes as well. Importantly, if PUCs can use time-variant pricing to systematically reduce peak demand, they can reduce the need to build additional generating capacity. Peak demand frequently requires powering up additional generation, typically less efficient natural gas plants that can be brought on line relatively quickly, known as "peaker plants."[261] If peak load can be reduced through pricing, these peaker plants need not be built or brought on line. Estimates are that only sixty to one hundred hours out of the total number of yearly hours of electricity use (8760 hours) account for between 10 and 18 percent of our capacity needs.[262]

Similarly, if time-variant pricing results in reduced energy usage overall, not just shifts in usage based on time of day, it can contribute to GHG emissions reduction goals. And time-variant pricing, together with other forms of demand

257. *See* MASS. INST. TECH., *supra* note 21, at 145–67; *see also* ANDERSON, *supra* note 60, at 102–110.
258. *See* ANDERSON, *supra* note 60, at 146–47.
259. *See* AHMAD FARUQUI & SANEM SERGICI, HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EXPERIMENTAL EVIDENCE 3 (2009).
260. For example, utilities in the Northeast successfully relied on demand response programs, including dynamic pricing, to manage supply and demand loads during the polar vortex in 2014. *See* FED. ENERGY REGULATORY COMM'N, STAFF REPORT: ASSESSMENT OF DEMAND RESPONSE & ADVANCE METERING 12 (2014).
261. *See Half of Power Plant Capacity Additions in 2013 Came From Natural Gas*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/todayinenergy/detail.cfm?id=15751 (last updated Dec. 16, 2015) (explaining that natural gas plants are typically used as peaker plants).
262. *See* MASS. INST. TECH., *supra* note 21, at 146. Estimates about the capacity of dynamic pricing to reduce peak usage in the residential sector range as high as 100,000 megawatts, which is 10 percent of current overall installed capacity. *See* Harvey Michaels & Kat Donnelly, *Energy Innovation: Architecting the Consumer Side of the Grid for Energy Efficiency* 12 (Mass. Inst. of Tech. Indus. Performance Ctr., Working Paper No. 11-004, 2011).

response and direct load control, could play an important role in integrating more wind and solar power into the grid.[263] Because these resources are variable and intermittent, they cannot be dispatched (turned on and off) like fossil-fuel-burning power plants.[264] And because electricity cannot currently be stored at significant scale, integrating higher amounts of these renewable resources into the grid without compromising system reliability is challenging.[265] Doing so in a way that minimizes the need for backup, carbon-based generation is a significant barrier to fully decarbonizing the grid. Time-variant pricing, together with other forms of demand response, could provide resources and capabilities to balance this intermittency.[266]

Time-variant pricing can take several forms. The simplest (and earliest) iteration, time-of-use (TOU), simply charges customers differential rates depending on the time of day (typically highest during the late afternoon, particularly during summer months) or even time of year (typically higher in the summer).[267] The other three principal forms of pricing are dynamic, altering prices based on actual changes in peak generation. They range from the simplest, charging customers more only on critically hot days (critical peak pricing), to slightly more complex, variable prices on critically hot dates (variable peak pricing), to real-time, where electricity usage is tied to the wholesale market price for electricity.[268] For residential customers dynamic pricing typically uses only the former two and only for those days with especially high usage. Thus, "time-variant" is a more accurate descriptor for most residential customers. Dynamic pricing is now possible with smart meters, and enabling technologies like programmable thermostats and "smart" appliances can help customers respond to peak pricing without having to manually control their usage. Some appliances and thermostats can even receive signals from a utility when prices are spiking and automatically adjust usage or temperatures downward.[269]

263. MASS. INST. TECH., *supra* note 21, at 150.
264. *See* INT'L RENEWABLE ENERGY AGENCY, RENEWABLE ENERGY INTEGRATION IN POWER GRIDS: TECHNOLOGY BRIEF 1 (2015), http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP_Tech_Brief_Power_Grid_Integration_2015.pdf [https://perma.cc/8R9H-AGGT].
265. *See* GENE BERRY, PRESENT AND FUTURE ELECTRICITY STORAGE FOR INTERMITTENT RENEWABLES 1 (2010), http://www.c2es.org/docUploads/10-50_Berry.pdf [https://perma.cc/7P59-3E3C].
266. *See* MASS. INST. TECH., *supra* note 21, at 143–48.
267. *See* Ahmad Faruqui & Sanem Sergici, Arcturus*: International Evidence on Dynamic Pricing*, 26 ELECTRICITY J. 55, 56–57 (2013).
268. *Id.*
269. *Id.* at 57–58.

Despite widespread installation of smart meters and the introduction of smarter appliances and thermostats, we have yet to see widespread time-variant pricing for residential customers. Estimates are that only two percent of households are on time-varying rates with an even smaller percentage on actually dynamic (as opposed to TOU) rates.[270] Dynamic pricing on the commercial and industrial side is more widespread and smart meters have accelerated its use.[271]

Most residential and small commercial programs to date, however, have been small, pilot experiments and penetration remains low in every state. More permanent programs are, without exception, opt-in programs and most of these have been plagued by low participation rates.[272] Yet the evidence about the effectiveness of these programs is largely positive. The most successful residential programs demonstrate reductions as high as 29 percent of peak usage from consumers enrolled in programs that use critical peak pricing and enabling technologies.[273] The reasons for low participation are varied, including consumer concerns about privacy[274] and the safety of smart meters.[275] But the

270. *See* Ahmad Faruqui et al., *Smart by Default: Time-Varying Rates From the Get-Go—Not Just by Opt-In*, 152 PUB. UTIL. FORT. 25, 25 (2014).

271. *See*, MASS. INST. TECH., *supra* note 21 at 161–62.

272. An exception is the residential time-of-use program offered by Arizona Power, which has attracted about half of residential customers in the service area through aggressive marketing. *See* Ahmad Faruqui, *For Customer Savings and Economic Efficiency, the Time for Dynamic Rates Is Now*, ELECTRICITYPOLICY.COM 8 (2012), http://www.electricitypolicy.com/images/pdf/faruqui-10-6-12-final.pdf [https://perma.cc/F2GH-NC9V].

273. *See* Faruqui & Sergici, *supra* note 267, at 56–57, 60 (evaluating thirty-four studies of residential pricing programs and concluding that the size of reductions in peak usage improves both as the ratio of peak prices to non-peak prices increases and in programs that incorporate enabling technologies like programmable thermostats and in-home displays of energy usage).

274. In January, 2015, the U.S. Department of Energy finalized a voluntary code of conduct for utilities and third parties about smart grid customer data, U.S. DEP'T OF ENERGY, DATA PRIVACY AND THE SMART GRID: A VOLUNTARY CODE OF CONDUCT (Jan. 12, 2015), https://www.smartgrid.gov/sites/default/files/VCC_Concepts_and_Principles_2015_01_08_FINAL_1.pdf [https://perma.cc/B49V-JH85], and the California PUC became the first to issue rules to protect privacy and the security of customer data. *See* Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, No. 11-07-056 (Cal. Pub. Utils. Comm'n, Jul. 29, 2011).

275. *See* CAL. COUNCIL ON SCI. & TECH., HEALTH IMPACTS OF RADIO FREQUENCY EXPOSURE FROM SMART METERS 1 (2011), http://www.ccst.us/publications/2011/2011smart-final.pdf [http://perma.cc/HDE7-A4ZM] (finding no known health risks from smart meters). Several states have adopted policies that allow consumers to opt out of having a smart meter installed, though the opt-out rate has been small. INST. FOR ELEC. INNOVATION, UTILITY-SCALE SMART METER DEPLOYMENTS: BUILDING BLOCK OF THE EVOLVING POWER GRID 1 (2014), http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf [https://perma.cc/F2UU-A75F].

cost implications for individual consumers, particularly low-income households, have also stymied reform despite evidence that widespread implementation of time-variant pricing could reduce consumer electricity bills by as much as $7 billion annually.[276]

One way to think about time-variant pricing is that it shifts the risk of swings in wholesale electricity prices from ratepayers as a class to the individual consumer, who bears the risk of swings in prices but no longer pays a risk premium as part of flat rates and can therefore also see significant cost savings by reducing peak use.[277] If prices spike under dynamic pricing, consumers can experience large increases in their utility bills unless they reduce their use. But recent pilot programs have shown that a large majority of low-income consumers benefit immediately from the implementation of peak pricing because they use less peak power than higher income households and are responsive to increases in electricity prices during peak periods and will reduce consumption.[278]

Nevertheless, most states have not moved to time-variant residential rates on a widespread basis, though the federal government has financed several pilot programs around the country with Oklahoma, Delaware, and Maryland adopting particularly promising programs.[279] Arizona's two principal IOUs have also had significant success in getting residential ratepayers to opt into time-of-use rates, with about half of Arizona Public Service customers doing so.[280] California and Massachusetts, however, are poised to mandate that all residential ratepayers of their IOUs and distribution utilities, respectively, be placed into a time-variant program unless they opt out. These regulatory experiments should demonstrate whether time-variant pricing can deliver the benefits its proponents believe possible, including significant cost savings for consumers.[281]

276. *See* Faruqui et al., *supra* note 270.
277. *See* AHMAD FARUQUI ET AL., INST. FOR ELEC. EFFICIENCY, THE IMPACT OF DYNAMIC PRICING ON LOW INCOME CUSTOMERS 4 (2010), http://www.edisonfoundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf [http://perma.cc/J9R9-GN76].
278. *See id.* at 26. The authors evaluated five residential time-variant pilot programs and found that between 65 and 79 percent of low income customers benefitted from the implementation of dynamic pricing without changing their behavior. *Id.*
279. *See* Faruqui et al., *supra* note 270, at 25–27.
280. *See* Faruqui, *supra* note 272, at 8.
281. *See* Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-Of-Use Rates at 88, No. 15-07-001 (Cal. Pub. Utils. Comm'n, Jul. 13, 2015) [hereinafter Cal. Pub. Utils. Comm'n]; MASS. DEP'T OF PUB. UTILS., *supra* note 181, at 19.

Although Massachusetts is a restructured state, as we described above, its PUC, called the Department of Public Utilities (DPU),[282] has made the adoption of time-variant rates in the residential sector a key component of its effort to modernize the state's electricity grid. And more than 75 percent of the state's residential customers remain customers of the incumbent electricity distribution utilities despite having retail choice.[283] Thus most residential customers in Massachusetts remain subject to DPU's regulatory reach in rate setting.

Central to the Massachusetts grid modernization effort is widespread adoption of time-variant rates to take advantage of DPU's order requiring its distribution utilities to install advanced metering infrastructure for all retail customers.[284] To that effect, DPU recently finalized an order that sets forth a policy framework for requiring default time-varying rates for basic residential service provided by the electric distribution providers.[285]

DPU is relying on such rates to improve system efficiencies, reduce peak demand, and improve the deployment of DERs such as solar.[286] The Department believes that a significant cause of the need for peak demand—30 percent of its generating capacity for just 10 percent of the year—is because its customers are not sufficiently price sensitive to the expense of peak capacity because they pay flat electricity rates.[287]

The key innovation here—striking in its simplicity—is the use of a default rule (choice architecture) that will automatically include residential customers in TOU pricing with a critical peak price rate plan rather than allowing customers the choice to opt in.[288] If they prefer, customers will be able to opt out of the de-

282. *See Department of Public Utilities (DPU)*, EXEC. OFFICE OF ENERGY & ENVTL. AFFAIRS, http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu [https://perma.cc/BSV6-NDNG] (last visited Mar. 21, 2016).

283. *See Electric Customer Migration Data*, EXEC. OFFICE OF ENERGY & ENVTL. AFFAIRS, http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/doer/electric-customer-migration-data.html [https://perma.cc/96NT-H92R] (last visited Mar. 21, 2016). By contrast, more than 90 percent of large industrial and commercial customers are serviced by competitive suppliers. *Id.*

284. *See* MASS. DEP'T OF PUB. UTILS., *supra* note 181, at 19.

285. *See* MASS. DEP'T OF PUB. UTILS., D.P.U. 14-04-C, ORDER ADOPTING POLICY FRAMEWORK FOR TIME VARYING RATES (2014), http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-04%2FOrder_1404C.pdf [http://perma.cc/HF5H-BN77]; *see also* MASS. DEP'T OF PUB. UTILS., D.P.U. 14-04-B, INVESTIGATION BY THE DEPARTMENT OF PUBLIC UTILITIES UPON ITS OWN MOTION INTO TIME VARYING RATES (2014).

286. *See* MASS. DEP'T OF PUB. UTILS., *supra* note 181, at 10–11.

287. *See id.*

288. There is a robust literature on the use of "choice architecture" and "default rules" to channel individual behavior. *See, e.g.*, RICHARD H. THALER & CASS R. SUNSTEIN, NUDGE: IMPROVING DECISIONS ABOUT HEALTH, WEALTH, AND HAPPINESS (2008).

fault plan into a flat-rate plan that offers a rebate for reducing usage during critical peak times.[289] This approach is the first of its kind in the country.[290]

Like Massachusetts, California (a hybrid state) is also moving to adopt a default, opt-out model for residential time-of-use (TOU) pricing.[291] The CPUC has long worked with its three major IOUs to offer TOU rates for commercial and residential customers and its IOUs are required to use TOU pricing for non-residential customers.[292] Residential customers of the IOUs have been offered TOU rates since 1977, but only a tiny percentage participate.[293] And in 1983 the state authorized the first Real Time Pricing program in the country, though the program was limited to a small number of large electricity users.[294] But it was the state's energy crisis in 2000 to 2001—with rolling blackouts caused by huge price spikes in electricity prices[295]—that led the CPUC to consider dynamic pricing for virtually all residential customers, a plan the CPUC adopted in July 2015 after years of study, pilot programs, and new legislation.[296]

The new rate design, which will be phased in over the next four years, simplifies the state's residential electricity tariffs and requires each of the state's three IOUs to offer a TOU tariff as their default approach to residential pricing. The details of these new tariffs are to be developed over time, with the CPUC at this point endorsing default TOU pricing "in principle."[297] In its order, the CPUC is requiring the IOUs to submit default TOU rate proposals that take into consideration customer acceptance and legal requirements, and create rate plans that allow customers to react flexibly to the grid and that offer a menu of different residential rates. The plans will not be mandatory but, again, will default

289. *See* MASS. DEP'T OF PUB. UTILS., *supra* note 181, at 2, 48–49.
290. *See* Laurie Guevara-Stone, *California Rolls Out Default Time-of-Use Rates*, CLEAN TECHNICA (June 8, 2015), http://cleantechnica.com/2015/06/08/california-rolls-out-default-time-of-use-rates [perma.cc/RL3E-YLAG] ("This is the first example of TOU pricing being the default at scale." (quoting RMI Senior Associate Mark Dyson)).
291. *See* Cal. Pub. Utils. Comm'n, *supra* note 281.
292. *See id.* at 88.
293. *See, e.g.*, *In re* SoCal. Edison Co. Ordered to Revise Its Proposed Time-of-Day Pricing Tariffs for Large Usage Customers in Compliance With General Order No. 96-A, 82 Cal. P.U.C. 437 (1977), 1977 WL 42821, at *3 (describing SCE's different time-of-day rates for summer and winter months). *See* Cal. Pub. Utils. Comm'n, *supra* note 281, at 90.
294. Re Pac. Gas & Elec. Co., 14 Cal. P.U.C. 2d 15 (1983) (No. 83-12-068,), 1983 WL 909368. Southern California Edison began its own study shortly thereafter. *See* Re S. Cal. Edison Co., 16 Cal. P.U.C 2d 721, 885 (1984) (No. 84-12-068,), 1984 WL 1021399; *see also* Lori A. Burkhart, *Real-Time Pricing-Allowing Customers to Respond*, 130 PUB. UTILS. FORT. 31 (1992).
295. *See* CAL. ENERGY COMM'N, FEASIBILITY OF IMPLEMENTING DYNAMIC PRICING IN CALIFORNIA 1 (2003) (setting forth the need to reduce peak demand through dynamic pricing and other demand response programs in response to the electricity crisis).
296. *See* Cal. Pub. Utils. Comm'n, *supra* note 281, at 88.
297. *Id.* at 129.

customers into them while allowing customers to opt out. The rate plans must be ready by 2018, for full rollout in 2019.[298]

One explanation for the slow uptake of residential dynamic rate programs is that effective programs require sophisticated program design, extensive marketing efforts, and expensive infrastructure improvements—most importantly advanced metering, but also enabling technologies.[299] With a number of states engaged in distribution system improvements that include smart meter installation, it stands to reason that dynamic pricing programs of one type or another will become more common across the country. But many states will likely want to wait and see what happens with the experiments underway in Massachusetts and California and the results of the federally sponsored pilot programs around the country.

As with the other rate reform innovations we have described, the federal government has played an important role in encouraging time-variant pricing, particularly in the residential sector, in three respects. First, and most importantly, it has heavily subsidized the deployment of advanced meters.[300] Second, by funding time-variant dynamic pricing pilots around the country, which can be labor intensive and costly to administer, it has provided valuable experience for efforts to design programs that will be effective and acceptable to customers.[301] Third, Congress has also encouraged states to experiment with various forms of dynamic pricing in both PURPA and the 2005 Energy Policy Act.[302] As with the other examples of innovative ratemaking we describe, the result is a diversity of policies to promote dynamic pricing, with Massachusetts using its ratemaking power to require its distribution utilities to offer default residential TOU pricing and California working with (and mandating) its IOUs to do so.

E. Lessons for Institutional Design

The four areas of innovation we have highlighted in this Part raise several broader questions regarding institutional design, a topic that we can only gesture

298. *Id.* at 5, 179.
299. *See* AHMAD FARUQUI ET AL., TIME-VARYING AND DYNAMIC RATE DESIGN 18–23 (2012) (describing challenges to and criteria necessary for successful dynamic pricing for residential consumers).
300. *See generally Advanced Metering Infrastructure and Customer Systems*, SMARTGRID, https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.html## [https://perma.cc/ZK8D-VU6D] (last updated Mar. 13, 2015).
301. *See Consumer Behavior Studies*, *supra* note 120; U.S. DEP'T OF ENERGY, *supra* note 120 (describing and evaluating pilot programs).
302. *See* 16 U.S.C. § 2621(d) (2012); ROSE & MEEUSEN, *supra* note 119, at 10.

to here. First, these examples show how different states across the three models of electricity regulation are using their ratemaking powers to promote innovation across all of the major aspects of the machine that state PUCs still regulate—from generation to distribution to customer end use. They also suggest that each of the different models has certain advantages depending on which aspect of the machine one is focused. As a result, there is value not only in the fact of state experimentation but also in the diversity of models that we have inherited after restructuring. This diversity has, we suggest, created opportunities for a range of experiments and innovation that we might not see under a single uniform approach.

Second, the focus on ratemaking raises a larger set of questions about the relative merits of different ways of supporting innovation. Obviously, governments use a variety of tools to support innovation, including intellectual property protection, subsidies and tax incentives, government funded R&D, and direct and market-based regulation. And while we almost always end up with some mix of these, scholars and policymakers have so far not fully appreciated the role of ratemaking as a tool for supporting certain kinds of investments necessary to complete the innovation cycle and bring expensive technologies and new practices to maturity.[303] Given the truly massive task of decarbonizing the power sector over the coming decades, ratemaking could turn out to be a critical tool in facilitating and scaling key innovations necessary for a low-carbon electricity system—all of which raises complex distributional and efficiency questions.[304] At a minimum, ratemaking deserves consideration alongside these other tools for supporting innovation.

Third, the case studies also demonstrate the important role that the federal government, and particularly the Department of Energy, has played in helping nudge states to use their ratemaking powers to promote innovation and in bearing some of the financial risk of doing so. The federal government's support in

303. *But see* Monast & Adair, *supra* note 169 (discussing role of PUCs and ratemaking in "completing the innovation cycle" for technologies such as CCS); Boyd, *supra* note 13, at 1704–08 (discussing role of PUCs and ratemaking generally in experimentation and innovation).

304. Distributional questions, particularly those involving cross-subsidies between classes of ratepayers and, more generally, the proper balance between ratepayers and utility investors, have long been at the center of debates over ratemaking and rate design. *See, e.g.*, BONBRIGHT ET AL., *supra* note 62, at 85–107 (discussing different functions and competing objectives of public utility rates). For an early and influential treatment of the broader distributional consequences of ratemaking, *see* Richard A. Posner, *Taxation by Regulation*, 2 BELL J. ECON. & MGMT. SCI. 22, 29 (1971) (positing that utility rates frequently result in cross-subsidies from certain classes of consumers to others and developing a theory to explain rate regulation as, in part, "a method of public taxation"); *see also* John S. Moot, *Economic Theories of Regulation and Electricity Restructuring*, 25 ENERGY L.J. 273 (2004) (endorsing the Posner theory).

this respect has allowed states to self-select into the role of policy innovator by encouraging and subsidizing experimentation in different areas, from generation to large-scale investment in the distribution system. Given the existence of the different regulatory models in use across a wide range of states, this process of self-selection has resulted in a diversity of innovations while simultaneously honoring state policy preferences. At the same time, the federal government has not been very systematic in guiding state experimentation. As noted, there are limits to the conclusions one can draw from any single experiment, particularly one as complicated as the Kemper project. Ideally, the federal government would have supported multiple commercial-scale CCS projects across different states with different political and regulatory environments to provide a more substantial basis for learning. Similarly, the $4.4 billion invested in smart meters under the American Recovery and Reinvestment Act did not require utilities that received funding to use them for time-variant pricing or other clean energy innovations.[305] Nor did the federal government seek to design and coordinate the various smart grid pilots it supported across the country with an eye toward a more systematic appraisal, further limiting the conclusions that could be drawn from these experiments.[306]

Yet in the second-best world we are in, with limited appetite or ability at the federal level to orchestrate a series of commercial scale experiments, the few individual experiments that have moved forward are surely better than none at all. Moreover, the Recovery Act money was allocated with considerable urgency given dire economic circumstances, making it understandable why the subsidies for smart meters were not tied to competitive grant making or conditioned in other ways.[307] These critiques do suggest, however, that the federal government, and particularly the Department of Energy, in providing various incentives and nudges to states, would benefit from a more systematic appraisal of how to make best use of the three-model system and the diversity of experimentation that DOE can support.

Finally, the case studies provide evidence regarding the power of ratemaking as a key tool for climate policy. In the debate over how to reduce U.S. GHG emissions by 80 percent by 2050, most scholars and policymakers have

305. *See, e.g.*, Stephanie Joyce, *Why Smart Meters Don't Make a Smart Grid*, INSIDE ENERGY (May 16, 2015), http://insideenergy.org/2015/05/16/why-smart-meters-dont-make-a-smart-grid [https://perma.cc/Q2BL-9F52].

306. *See* Joskow, *supra* note 28, at 43–45 (discussing problems with existing smart grid pilots and need for well-designed experiments going forward).

307. *See* Michael Grabell, *How Not to Revive an Economy*, N.Y. TIMES (Feb 11, 2012), http://www.nytimes.com/2012/02/12/opinion/sunday/how-the-stimulus-fell-short.html [https://perma.cc/L9JK-36UU].

emphasized traditional policy tools such as cap-and-trade, taxes, tax incentives, and conventional command-and-control regulation.[308] Some have also advocated for large increases in federal spending on energy research.[309] Each of these policy options has significant merit; each also has significant cost, either in taxpayer subsidies or in financial burdens on regulated entities. Perhaps more problematic, each policy option also faces substantial political opposition, especially at the federal level. To date, with the exception of tax incentives for renewable energy and some federal spending on energy research, none of these policy options has garnered lasting congressional support.[310] And even with a policy intended to force large emitters to reduce their GHG emissions, such as putting a price on carbon, the kinds of large investments in low-carbon electricity needed to get to the 2050 decarbonization goals may never materialize. The market structure of electricity pricing up to this point has failed to incentivize sufficient investment in low-carbon generation and it is unclear whether a carbon price by itself would solve the problem.

Using innovative ratemaking to encourage investments in a low-carbon electricity system is, we contend, a policy tool that ought to receive significantly more attention because it allows states to socialize the cost of large infrastructure investments across ratepayers and thus may garner less political opposition than carbon reduction efforts in Congress or state legislatures. Spreading such costs through electricity rates may also be a fairer way to distribute costs across users of the services the infrastructure investments will provide since rates can be set to reflect

308. *See, e.g.*, HSU, *supra* note 5; Metcalf & Weisbach, *supra* note 5; Nordhaus & Gutherz, *supra* note 7.

309. Two important examples are John P. Holdren, *The Energy Innovation Imperative: Addressing Oil Dependence, Climate Change and Other 21st Century Energy Challenges*, 1 INNOVATIONS 3, 19 (2006) and Bill Gates, *We Need Clean-Energy Innovation, and Lots of It*, GATESNOTES (July 29, 2015), https://www.gatesnotes.com/Energy/Energy-Innovation [https://perma.cc/7JAW-WKTL].

310. Not only has Congress failed to pass a cap-and-trade program for greenhouse gases, but the House of Representatives has voted to repeal the President's central climate change initiative, the Clean Power Plan. *See* Stephen Power, *Senate Halts Effort to Cap CO_2 Emissions*, WALL STREET J. (July 23, 2010), http://www.wsj.com/articles/SB10001424052748703467304575383373600358634 [https://perma.cc/7AKH-4FWF]; Alan Neuhauser, *Welcome Back, Mr. President: House Votes to Scrap Environmental Regs*, U.S. NEWS & WORLD REP. (Dec. 1, 2015), http://www.usnews.com/news/articles/2015/12/01/house-votes-to-scrap-obamas-clean-power-plan [https://perma.cc/2DCX-CNX2]. Congress has, however, extended the investment and production tax credits for wind, solar and other renewable energy sources, most recently in December of 2015. *See* Stephen Lacey, *Congress Passes Tax Credits for Solar and Wind: 'Sausage Making at Its Most Intense'*, GREENTECH MEDIA (Dec. 18, 2015), http://www.greentechmedia.com/articles/read/breaking-house-passes-1.1-trillion-spending-bill-with-renewable-energy-tax [https://perma.cc/ZB8Y-7SM6]. For an overview of federal spending on research and development, including energy, see JOHN F. SARGENT, JR., FEDERAL RESEARCH AND DEVELOPMENT FUNDING: FY 2015 (2015), https://www.fas.org/sgp/crs/misc/R43580.pdf [https://perma.cc/Z4QR-D4EV].

considerations like amount of electricity consumed and even ability to pay. Without question, there are risks that ratemaking can be distorted by capture or burden ratepayers with too much risk. And ratemaking may not always be the best tool to support innovation. It nevertheless deserves more attention as an important potential mechanism to decarbonize the power sector.

III. ACCIDENTS OF FEDERALISM? DIVERSITY AND EXPERIMENTALISM IN PUBLIC UTILITY LAW

Despite the diversity of promising regulatory experiments we have described, the federal structure of U.S. electricity law garners plenty of criticism, along with calls for new statutory fixes that would remove some of the obstacles to a more rational system that can better respond to new problems.[311] Most of this commentary implies or even makes explicit that more uniformity rather than less would result in an improved ability to achieve certain goals.[312] Our examples suggest, however, that the Federal Power Act (FPA)'s commitment to preserving significant areas of state authority (and Congress's subsequent reticence to disturb this balance of responsibility), may have produced more benefits than previously recognized. When combined with federal policy nudges and federal subsidies in the form of direct grants, tax credits, and loan guarantees, the U.S. system of energy regulation—accidental though it may be—appears to be generating substantial experimentation and innovation across all major aspects of the grid.

It is difficult to know, of course, whether a more uniform system of federal regulation would produce a more innovative power sector than the one we have. But given the complexity of the machine at its center, combined with the need for dramatic reductions in GHG emissions over the coming decades, a system that maximizes policy experimentation may turn out to be more of an asset than we realize. Moreover, given differences in fuel sources, political preferences, electricity prices and other local circumstances, policy variability embraces local diversity in ways that seem to promote experimentation. To be sure, the federal government could do a better job guiding and disciplining the policy experimentation

311. *See*, *e.g.*, Freeman & Spence, *supra* note 16, 43–62 (arguing that Congress should amend the Federal Power Act to impose more rationality, provide more guidance to FERC in adopting power markets to changing conditions); *see also* Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 U. ILL. L. REV. 1 (2014). *But see* STEVE ISSER, ELECTRICITY RESTRUCTURING IN THE UNITED STATES 18–19 (2015) (describing the process of energy restructuring as "muddling through," though suggesting that given the complexity of power markets this may have been the only reasonable alternative).

312. *See* discussion *supra* note 14.

that is occurring. But the diversity that we see in the current system is clearly an asset that is worth exploiting.

The move to restructure electricity markets in the 1990s was, as we explained above, intended to replace regulation with competition in large segments of the industry. Although Congress made clear in the Energy Policy Act of 1992 that competition in electricity was an important policy goal, it never legislated in any detail on the topic, leaving FERC to push competition as far as it could under its existing FPA authority.[313] Despite FERC's ambitions, along with those of a number of states, to fully restructure both wholesale and retail electricity across the country, their efforts did not fully carry the day. In the end, not all states participated in restructuring and quite a few pulled back after the California electricity crisis. And they had the ability to do so precisely because the federal scheme allowed them to. The result is the three models we have categorized as traditional, restructured, and hybrid.

Our central claim is that there is today—in this moment of significant change in the industry (the kind of moment that comes around maybe once in a generation)—considerable but underappreciated value in this diversity, illustrating perhaps (once again) the genius, accidental or otherwise, of our federal system. It may be, in other words, that the failure of restructuring—its limited reach—has left us with resources that we might not otherwise have as we face the daunting task of trying to decarbonize the power sector over the coming decades. And this is true, we argue, regardless of whether Congress passes significant federal legislation to address climate change. Even with new federal legislation creating a cap-and-trade program, adopting a carbon tax, or deploying some other mix of policy instruments, we will need every successful innovation in low-carbon electricity available—nuclear, carbon capture and storage, smart grids, distributed generation, storage, efficiency, demand response, and much more—to have even a chance of hitting ambitious decarbonization targets by mid century and beyond. Any comprehensive federal policy will also need to learn from mistakes and failures and build on successes based on the diversity of experiences across the different models and across all aspects of the electricity system. The more experiences we have, the more opportunity for successes and failures. When it comes to decarbonizing the electric power sector, it might be a good thing that restructuring did not carry the day. We may be better off with the mess we have.

313. For a detailed description of the leadership role FERC took in opening up wholesale power markets, with limited involvement by Congress, see discussion *supra* notes 80–82.

The great appeal of a single, uniform model of regulation is, of course, efficiency.[314] Given that the power system operates as one big machine, developing a single regulatory framework to govern the machine has obvious merits and would, in many cases, deliver significant efficiencies not available under the balkanized approach of today. Regulation of the machine, in this respect, might be viewed as a quintessential federal function. Leaving Texas, Alaska, and Hawaii aside, the two major interconnects that comprise our electric power system extend across the entire country, connecting millions of component parts and individual devices—all operating, as the Supreme Court once put it, in "electromagnetic unity."[315] If ever a sector should be regulated top-to-bottom by the federal government, one might argue, it is electricity.[316] Congress clearly recognized this possibility when it enacted Part II of the FPA in 1935. It could have gone much further than it did in extending its authority under the commerce power to regulate electricity.[317] But it chose not to do so precisely

314. *Cf.* Conn. Light & Power Co. v. Fed. Power Comm'n, 324 U.S. 515, 530 (1945) ("Congress is acutely aware of the existence and vitality of . . . state governments. It sometimes is moved to respect state rights and local institutions even when some degree of efficiency of a federal plan is thereby sacrificed. Congress may think it expedient to avoid clashes between state and federal officials in administering an act such as [the Federal Power Act]. Conflicts which lead state officials to stand shoulder to shoulder with private corporations making common cause of resistance to federal authority may be thought to be more prejudicial to the ends sought by an act and regulation more likely to be successful, even though more limited, if it has local support.").

315. Fed. Power Comm'n v. Florida Power & Light, 404 U.S. 453, 460 (1972); *see also* New York v. FERC, 535 U.S. 1, 7 (2002) ("[U]nlike the local power networks of the past, electricity is now delivered over three major networks, or 'grids,' in the continental United States. Two of these grids—the 'Eastern Interconnect' and the 'Western Interconnect'—are connected to each other. It is only in Hawaii and Alaska and on the 'Texas Interconnect'—which covers most of that State—that electricity is distributed entirely within a single State. In the rest of the country, any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.").

316. *Cf.* Henry N. Butler & Jonathan R. Macey, *Externalities and the Matching Principle: The Case for Reallocating Environmental Regulatory Authority*, 14 YALE L. & POL'Y REV. 23, 25 (1996) (suggesting that the geographic scope of an environmental problem should determine the appropriate level of governmental jurisdiction to solve it).

317. *See Conn. Light & Power Co.*, 324 U.S. at 529–30 ("It has never been questioned that technologically generation, transmission, distribution and consumption are so fused and interdependent that the whole enterprise is within the reach of the commerce power of Congress, either on the basis that it is, or that it affects, interstate commerce, if at any point it crosses a state line. Such a broad and undivided base of jurisdiction of the Power Commission would be quite unobjectionable and perhaps highly salutary if the United States were a unitary government and the only conflicting interests to be considered were those of the regulated company."); *see also id.* at 530 (noting that in preserving state jurisdiction over electricity, Congress may have thought it "wise to keep the hand of state regulatory bodies in this business, for the 'insulated chambers of the states' are still laboratories where many lessons in regulation may be learned by trial and error on a small scale without involving a whole national industry in every experiment.").

because of the value it placed on state regulation.[318] And, although Congress has adjusted the structure and practice of electricity regulation since 1935, it has refrained from disturbing the basic jurisdictional scheme despite passing four major pieces of omnibus energy legislation since 1978.[319]

Indeed, under a single, uniform model, we lack the opportunity to gain the advantages typically associated with federalism.[320] One of these, clearly, is policy experimentation and innovation. Though some scholars suggest that federalism is unlikely to produce such innovation,[321] we think the current system of electricity regulation, with its three discrete models together with federal policy nudges and subsidies, is doing precisely that.[322] It also seems unlikely that a uniform system would produce the kind of parallel but distinct experiments across the different models that we see today from generation to end use and everything in between.

As we have shown, traditional cost-of-service states, for example, are using their ratemaking powers to facilitate large-scale investments in risky, low-carbon generation technologies in partnership with their utilities, which continue to own and operate generation. PUCs in these states determine the extent to which the costs of large-scale generation can be recovered in rates and, importantly, have significant power to reduce the risk utilities face in developing new technologies through the way they apply traditional standards of prudency and "used and useful" review. The utilization of this power, combined with federal subsidies, has

318. *See, e.g.*, S. REP. NO. 621, at 48 (1935) (discussing the "policy of Congress" in the proposed Part II of the FPA "to extend regulation to those matters which cannot be regulated by the States and to assist the States in the exercise of their regulatory powers, but not to impair or diminish the powers of any State commission"); H.R. REP. NO. 1318, at 8 (1935) ("The bill takes no authority from State commissions and contains provisions authorizing the Federal Commission to aid the State commissions in their efforts to ascertain and fix reasonable charges. . . . The new parts are so drawn to be a complement to and in no sense a usurpation of State regulatory authority and contain throughout directions to the Federal Power Commission to receive and consider the views of State commissions. Probably, no bill in recent years has so recognized the responsibilities of State regulatory commissions as does title II of this bill."); *see also Conn. Light & Power Co.*, 324 U.S. at 525 ("Progress of the bill through [the] various stages shows constant purpose to protect rather than to supervise authority of the states."); *cf.* Oneok, Inc. v. Learjet, Inc., 135 S. Ct. 1591, 1599 (2015) ("As we have repeatedly stressed, the Natural Gas Act was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way.").

319. *See* Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117; Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776; Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594; Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 121 Stat. 1492.

320. For a recitation of the familiar arguments, see Carlson, *supra* note 19.

321. *See, e.g.*, Rose-Ackerman, *supra* note 18; Galle & Leahy, *supra* note 18; *see also* Rubin & Feeley, *supra* note 18.

322. For a defense of the notion that federalism produces policy innovation, see, for example, SHAPIRO, *supra* note 18 (citing theoretical and empirical evidence of policy innovation).

yielded valuable information about the viability and cost-effectiveness of new nuclear reactors and advanced coal plants with carbon capture and storage. At least to date, these traditional PUCs appear to be less interested in promoting innovative approaches to the modernization of local distribution systems or in the ways in which retail rates are set, at least among residential ratepayers. This is curious given that federal subsidies for advanced metering and pilot programs for residential time-of-use rates are available nationwide.[323]

The reasons for this reluctance are not entirely clear. But it may be that restructured and hybrid states that have unbundled generation from transmission and distribution and have less control over the development of generation (relying instead on the wholesale markets) are more likely to use the power they have retained—over distribution in the case of the restructured states and distribution and retail rates in the hybrid states—in more creative ways. In other words, as they have lost the power to encourage and compensate utilities for building generation, some PUCs and state legislatures in hybrid and restructured states have focused more on what remains within their purview and realized that their powers over the remaining portions of the machine, especially their ratemaking powers, are significant. Thus Massachusetts, as we explained, is using its ratemaking powers over only those customers who have not exercised retail choice to implement time-of-use pricing. And it is focusing on its distribution utilities to encourage grid modernization by using advanced cost recovery and up front prudency determinations that look a lot like the kinds of ratemaking traditional states are using to incentivize generation investments. Minnesota, a hybrid state, is engaged in using rate design to encourage distributed solar energy while ensuring that tariffs for the use of the distribution system are adequate to compensate incumbent utilities for the infrastructure they provide. California is engaged in a similar process to encourage and incorporate distributed generation resources while also using dynamic rates to more effectively manage energy use. Each of the innovations we have highlighted is, in some ways, remarkably similar in harnessing the ratemaking power of PUCs. But the three models produce quite different substantive outcomes.

There is, of course, a significant downside to leaving the fifty states to decide whether and how much to innovate. Some—indeed even a majority—can refuse to do so. In this respect, stronger nudges, more funding, and more targeted incentives from the federal government might help. And a robust federal policy on carbon emissions is likely necessary to drive decarbonization over the long term.

323. *See Recovery Act*, U.S. DEP'T OF ENERGY, http://energy.gov/oe/information-center/recovery-act [perma.cc/A74Q-TH5G] (last visited Mar. 21, 2016) (describing grantmaking process).

That said, it seems unlikely that there will be a major shift in the three-model system of electricity regulation any time soon, and this system has produced more experimentation across different aspects of the power sector than is conventionally acknowledged. If federalism works as is often predicted, successful innovations may eventually diffuse beyond state borders to states that have to date sat on the sidelines, particularly if the Clean Power Plan takes effect.

We have said less about why certain PUCs across the three models have chosen to innovate while others have lagged behind. At this point, we have some preliminary observations but more research is needed to draw firmer conclusions.[324] Some of the innovation surely comes from political leadership and policy preferences. It is not, we think, an accident that more environmentally progressive states like California, Massachusetts, and New York are promoting rate innovations to produce a grid more reliant on renewables and DERs. These states have also been leaders on aggressive state climate policies like the Regional Greenhouse Gas Initiative in the Northeast and California's Global Warming Solutions Act.[325] But there are likely more prosaic explanations as well. The leader states frequently have more staff and larger budgets, which can be particularly important in designing and implementing complex programs like dynamic pricing. They may have dedicated sources of revenue and are therefore less subject to budgetary fluctuations. Some, like New York and California, have long histories of innovating and thus their staffs may view themselves as policymakers, not just approvers of utility-proposed rate increases.[326] At this point we can only observe that there are leaders and laggards across all three models of electricity regulation and offer preliminary explanations for why that may be so. More research can help us to understand individual PUC motivations and capabilities, including the incentives affecting the behavior of commissioners and their staffs,

324. There is a vast literature in political science about why some states innovate (innovation in this literature is defined simply as whether a state adopts a policy new to it) whereas others lag, and how innovative policies travel across different jurisdictions. The seminal article is Jack L. Walker, *The Diffusion of Innovations Among the American States*, 63 AM. POL. SCI. REV. 880, 881 (1969); *see also* Virginia Gray, *Innovation in the States: A Diffusion Study*, 67 AM. POL. SCI. REV 1174, 1182 (1973) (finding that per capita wealth and degree of political competition correlate positively with state innovation); Frederick J. Boehmke & Paul Skinner, *State Policy Innovativeness Revisited*, 12 ST. POL. & POL'Y Q. 303 (2012) (constructing a state innovation index based on 180 different policies and finding that California leads state innovation by a large measure).

325. *See Welcome*, REG'L GREENHOUSE GAS INITIATIVE, http://rggi.org [http://perma.cc/B86P-NV2K] (last visited Mar. 21, 2016) (describing RGGI members and policies); *Assembly Bill 32 Overview*, CAL. ENVTL. PROT. AGENCY AIR RES. BD., http://www.arb.ca.gov/cc/ab32/ab32.htm [perma.cc/759G-2A89] (last visited Mar. 21, 2016).

326. For an argument that we pay too little attention to the structure, funding, and history of state regulatory agencies, see generally Ann E. Carlson, *Regulatory Capacity and State Environmental Leadership: California's Climate Policy*, 24 FORDHAM ENVTL. L. REV. 63 (2013).

as well as how larger institutional and political dynamics can both constrain or enable PUC capacity for experimentation.

If one accepts that significant uncertainty exists about what mix of technologies, institutions, practices, and behaviors will deliver substantial decarbonization by 2050, a strong case can be made that our three-model system may actually outperform a more uniform national system in producing experimentation. We don't know whether DG will make up 5 percent or 50 percent of the electric generating mix in 2050, and there are credible studies supporting both numbers.[327] We don't know if a breakthrough in storage technology will allow for much higher penetration of intermittent renewables or push large numbers of people to exit the grid entirely.[328] We don't know how much new nuclear will be available at mid century or whether carbon capture and storage is viable.[329] And we certainly don't know how much and in what ways consumers will change their behavior in response to new technologies, more sophisticated pricing options, and nudges of one sort or another. More, not less, policy experimentation can help provide answers to these questions.

This leads to two additional observations. First, much of the debate about electricity regulation over the last twenty years has been framed as an ongoing battle between regulation and markets (or, in more recent discussions, between rent-seeking monopolists and the forces of disruption).[330] In fact, as the legal realists and institutional economists pointed out long ago,[331] the idea that markets and regulation (or law and the economy) can somehow be separated often obscures more than it clarifies. This is especially true in electricity, given the complexities of operating the system and the need for central administration and management of the grid under any circumstance. In the organized wholesale power markets, for example, multiples layers of regulation are required to make the markets function, more regulation in some respects than in the traditional

327. *See, e.g.*, NAT'L RENEWABLE ENERGY LAB., RENEWABLE ELECTRICITY FUTURES STUDY 1 (2012) (identifying 5 percent as upper limit of DG contribution to 80 percent renewables by 2050); AMORY B. LOVINS, ROCKY MOUNTAIN INST., REINVENTING FIRE: BOLD BUSINESS SOLUTIONS FOR THE NEW ENERGY ERA (2011) (suggesting DG could account for as much as 50 percent of generation capacity by 2050).

328. California has mandated that its IOUs procure 1325 megawatts of energy storage capacity by 2020. *See* Decision Adopting Energy Storage Procurement Framework and Design Program, No. 13-10-040 (Cal. Pub. Util. Comm'n 2013).

329. *See* Richard Anderson, *Nuclear Power: Energy for the Future or Relic of the Past?*, BBC NEWS (Feb. 27, 2015), http://www.bbc.com/news/business-30919045 [https://perma.cc/FYE4-R3PS]; INT'L ENERGY AGENCY, CCS 2014: WHAT LIES IN STORE FOR CCS? (2014) (assessing potential of CCS and obstacles to deployment).

330. *See* Boyd, *supra* note 13, 1630–31, 1661–74 (discussing these debates).

331. *Id.* at 1648.

cost-of-service states.[332] Even in fully restructured states, moreover, significant portions of the industry (transmission and distribution) are still regulated under a traditional public utility approach. By framing all of this as a battle between regulation and markets, we underplay the role that public utility regulation plays in all of these models.[333] In doing so we may be missing important opportunities to foster policy innovation.

Second, contemporary climate policy discussions have focused almost exclusively on various policy instruments directed at reducing emissions (cap-and-trade, carbon taxes, emissions performance standards, and the like) or increasing renewable generation (through renewable portfolio standards, tax credits, and so forth).[334] While these discussions have obvious import, they also ignore the fundamental role electricity ratemaking can and will have in channeling investments and changing behaviors across the whole range of technologies, practices, and behaviors that make up the electric power system. Ironically, EPA's Clean Power Plan regulations under Section 111(d) of the Clean Air Act—subject to criticism on numerous grounds including that Congress should legislate on a clean slate,[335] that the Clean Air Act is ill-suited for climate regulation,[336] that Section 111(d) is too untested and too vague to serve as a basis for climate policy[337]—appears to have as one of its primary virtues a system of regulation that embraces diversity in states and allows experimentation across the entire power system. By providing states with principal authority to design their own plans to reduce carbon emissions from the power sector, by allowing "beyond the fenceline" reductions (new low-carbon generation, improvements in energy efficiency, and so forth), and by permitting regional approaches that track the geography of wholesale power markets, the regulations may enhance the prospects of

332. *Id.* at 1663–64.
333. *Id.* (arguing for the importance of a revitalized and expanded concept of public utility in the context of efforts to decarbonize the power sector).
334. *See* 42 U.S.C. § 7411(d) (2012); HSU, *supra* note 5; Metcalf & Weisbach, *supra* note 5; Nordhaus & Gutherz, *supra* note 7.
335. *See* Jody Freeman, *Teaching an Old Law New Tricks*, N.Y. TIMES (May 29, 2014), http://www.nytimes.com/2014/05/30/opinion/teaching-an-old-law-new-tricks.html [http://perma.cc/NZS4-AM83] (describing the Clean Power Plan as "the sad reality of climate policy in the United States circa 2014" and adding that "[w]ith Congress paralyzed on the issue, the country's climate and energy policy is being made in arcane legal battles over the meaning of single phrases in statutes written long ago, leaving government and industry to duke it out in court").
336. This was one of the bases for EPA refusing to regulate greenhouse gases under the Clean Air Act until forced to do so by the Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497 (2007).
337. *See generally* Philip A. Wallach & Alex Abdun-Nabi, *Debating the EPA's Clean Power Plan Proposal—The Clean Power Plan's Equity Problems*, BROOKINGS INST. (Aug. 5, 2014, 9:00 AM), http://www.brookings.edu/blogs/planetpolicy/posts/2014/08/05-clean-power-plan-equity-problems-wallach-abdun-nabi [http://perma.cc/76YD-AVXU].

technological innovation across the sector. Because different parts of the electric power sector have to be approached in different ways, different kinds of rates and rate designs are necessary to maximize the collective effort to decarbonize the grid. EPA's new rules embrace this reality.

We also think our focus on the innovation produced by the three models of electricity regulation within a complex federal system casts interesting light on a number of theoretical debates about federalism. Some of these accounts suggest that the U.S. system of federalism should produce too little innovation because states face a classic free rider problem, particularly for policies that have a high risk of failure. States will rationally decide not to take policy risks, hoping they can free ride on the experimentation of other states if that experimentation leads to policy success.[338] If states take risks, their residents receive only some of the benefits and bear all of the downside—other states and the federal government gain the benefits of knowledge of what works and what doesn't while the experimenting state bears all of the losses from policy failure.[339] If all states reason in this way, little experimentation will result. Proponents of this theory argue that this lack of incentive to innovate is exacerbated by political incentives, with politicians reasoning that short-term policy failure will reduce their chances for reelection and that long-term policy success will produce little electoral advantage.[340] The problems of freeriding are even more acute in the case of policies to reduce GHG emissions: No state can solve the problem of climate change, nor can any state fully realize the benefits of regulating emissions. The lack of incentive to innovate here seems strong.[341]

Nevertheless, across numerous domains, states are innovating, including in health care, environmental policy, welfare reform, and employment law.[342] Some state climate policies, in fact, are among the strongest and most innovative in the world.[343] Scholars speculate that states engage in climate policy innovation for a number of reasons, including competition for investment and for electoral

338. Susan Rose-Ackerman's article is the leading exposition of this view. Rose-Ackerman, *supra* note 18; *see also* Galle & Leahy, *supra* note 18; SHAPIRO, *supra* note 18, at 85–86); Yair Listokin, *Learning Through Policy Variation*, 118 YALE L.J. 480, 544 (2008).

339. *See* WINSTON HARRINGTON, RES. FOR THE FUTURE, PROMOTING INNOVATIVE CLIMATE ADAPTATION THROUGH FEDERALISM 4 (2010).

340. *Id.*; *see also* Listokin, *supra* note 338, at 545–46.

341. *See* Carlson, *supra* note 19.

342. *See* SHAPIRO, *supra* note 18, at 86–88.

343. *See* DAVID BUCHAN, OXFORD INST. FOR ENERGY STUD., CALIFORNIA'S CLIMATE POLICY—A MODEL? (2010) (analyzing California's policies and concluding that other jurisdictions can learn lessons from them); *Emissions Trading*, CLIMATE NEXUS http://climatenexus.org/learn/solutions-policy/emissions-trading [perma.cc/XG7L-PXY4] (last updated Sept. 25, 2015) (describing the Regional Greenhouse Gas Initiative and calling it a "model").

advantage.[344] But the misaligned incentives to innovate probably produce too little innovation even though some states continue to innovate despite the risks.

One way to overcome these incentive problems is for the federal government to bear some of the risk of policy failure. Grant programs to states, for example, can both incentivize policy experimentation and shift costs for risk-taking away from a state's taxpayers.[345] And the federal government can step in and mandate state involvement in the implementation of policy, something commonplace in federal environmental statutes like the Clean Air Act, which sets overall air quality standards but leaves largely to the states the question of how to meet those standards.[346]

Our case studies of ratemaking in the electricity sector demonstrate that policy innovation appears to be occurring despite significant risk that some of the policies may result in expensive failures. Moreover, this innovation appears to be occurring in ways that take advantage of the diversity of regulatory models in the delivery of electricity, with states operating under the traditional model using their ratemaking powers to support risky investments in capital-intensive low-carbon generation, states operating in restructured markets innovating on the distribution side, and hybrid states using IOUs to experiment with distribution, distributed generation, and the like. Some of this innovation may be occurring for the sorts of reasons states innovate on climate policy: for economic development purposes or to gain electoral advantage. One interesting twist in the case of ratemaking, however, is that federal intervention to reduce some of the risk that individual states bear may help explain both the diversity of experiments and their ambition. Federal grants and loan guarantees help explain state experimentation with large baseload generation (nuclear and CCS). Significant federal investment in advanced metering to allow for real-time pricing programs may also be partially responsible for state rate experimentation to encourage dynamic pricing. Federal pilot programs to encourage dynamic pricing are also helpful in reducing the risk of more widespread implementation by demonstrating how to design successful programs. And federal policy nudges—pricing policies to

344. *See* J.R. DeShazo & Jody Freeman, *Timing and Form of Federal Regulation: The Case of Climate Change*, 155 U. PA. L. REV. 1499, 1516–1521 (2007); Kirsten H. Engel & Scott R. Saleska, *Subglobal Regulation of the Global Commons: The Case of Climate Change*, 32 ECOLOGY L.Q. 183, 190–194 (2005); Barry G. Rabe et al., *State Competition as a Source Driving Climate Change Mitigation*, 14 N.Y.U. ENVTL. L.J. 1, 12–41 (2005).

345. *See* HARRINGTON, *supra* note 339,at 5 (2010); Listokin, *supra* note 338, at 551–52. *But see* Rose-Ackerman, *supra* note 18, at 615–16 (discussing problems with grants to offset risk).

346. The system of cooperative federalism in the Clean Air and Clean Water Acts are obvious examples. *See* 42 U.S.C. § 7410 (2012) (setting forth state role in implementing National Ambient Air Quality Standards); 33 U.S.C. §§ 1311(b)(2), 1342 (2012) (allowing states to implement National Pollution Discharge Elimination System).

encourage small renewable generation and mandates to states to consider dynamic pricing—have also helped drive state policy innovation.

To be sure, these federal interventions are not part of any grand scheme to create a coherent national energy policy, and they surely could have benefitted from more careful and deliberate design. But they have, we argue, created a climate of policy innovation that takes advantage of state diversity and allows for experimentation during a moment of great technological and regulatory change.

We suggest, then, that the current moment of innovative ratemaking in the electricity sector is at least partially a result of what we call accidents of federalism—unintended but positive byproducts of the failure of a fully restructured electricity sector to take root—combined with directed federal policy to help reduce the risk of state policy experimentation. One might even call it a form of accidental democratic experimentalism in which Congress and the federal govern-government "authorize and finance experimental reform by states."[347]

Our observations about this policy innovation are meant to be largely descriptive, not normative. Whether more innovation would have occurred in a fully restructured and more uniform national system is difficult to know. Whether the current three-model system is sufficiently well organized to capitalize on the various innovations across the sector is also hard to determine. Nevertheless, we do intend to challenge the mostly negative standard account of the federal structure of electricity regulation, with its suggestion that we lack a coherent national policy and rational system of regulation due to federal inaction. Instead, Congress has both retained its commitment to a strong state role in electricity regulation and used policy nudges and subsidies in ways that advance innovation in policymaking at the state level.

Our attention to the innovation that is occurring and the interaction of state and federal policy aligns us with an emerging school of federalism theory that suggests that states can be deployed not just for local ends but also to promote national policies and values.[348] The emergence and persistence of the three models of electricity regulation combined with federal subsidies and nudges are helping to promote low- and zero-carbon electricity at a time when the U.S. government is working to meet ambitious goals to cut carbon emissions. And they are

347. Michael C. Dorf & Charles F. Sabel, *A Constitution of Democratic Experimentalism*, 98 COLUM. L. REV. 267, 288 (1998). *But see* David A. Super, *Laboratories of Destitution: Democratic Experimentalism and the Failure of Antipoverty Law*, 157 U. PA. L. REV. 541 (2008) (criticizing democratic experimentalism on various grounds and highlighting its shortcomings in the context of antipoverty law).

348. *See* Gerken, *supra* note 19, at 1893–94; Gluck, *supra* note 19, at 1997 ("With almost every national statutory step, Congress gives states new governing opportunities or incorporates aspects of state law—displacing state authority with one hand and giving it back with the other.").

producing innovation by taking advantage of precisely those traditional values federalism is meant to promote: diversity and experimentation. Yet they are doing so at least in part because the federal government has allowed the states to continue operating as important players in the national system of electricity regulation.[349] Our description thus also provides another example of the dynamic interaction between and among levels of government, one that defies standard explanations of our federal system and that recognizes the important role the federal government often plays in creating and supporting policies that emerge from systems of federalism.[350]

CONCLUSION

When Congress passed Part II of the FPA in 1935, it sought to complement rather than replace existing state authority to regulate the electricity sector. In doing so, it recognized the value and importance of state policy experimentation and the traditional role of state PUCs in regulating electricity rates.

Today, despite significant change in the sector and in a moment of great technological and regulatory innovation, we are still working with the basic jurisdictional split established in 1935. Rather than modify this framework, and notwithstanding multiple opportunities to do so, Congress has left it largely intact, leaving states with the ability to choose whether and how to participate in electricity restructuring. The resulting system of regulation is messy and uneven, with three major models in operation across the country. But this three-model system, combined with specific federal policy nudges and subsidies that have worked to de-risk certain state experiments, is also facilitating innovation across many aspects of the electricity sector.

The standard, largely negative account of our current system of electricity regulation contends that we need a statutory overhaul to bring order and efficiency to

349. *See* Gluck, *supra* note 19, at 1996–97.

350. There is a large literature taking issue with formalist accounts of federalism that suggest either that states and the federal government operate in separate and largely independent spheres or only in formalized structures like cooperative federalism. *See generally* ERIN RYAN, FEDERALISM AND THE TUG OF WAR WITHIN (2011); SCHAPIRO, *supra* note 19, at 97–98 (2009); Kirsten H. Engel, *Harnessing the Benefits of Dynamic Federalism in Environmental Law*, 56 EMORY L.J 159 (2006); Carlson, *supra* note 19; David E. Adelman & Kirsten H. Engel, *Adaptive Federalism: The Case Against Reallocating Environmental Regulatory Authority*, 92 MINN. L. REV. 1796 (2008); William W. Buzbee, *Interaction's Promise: Preemption Policy Shifts, Risk Regulation, and Experimentalism Lessons*, 57 EMORY L.J. 145 (2007); William W. Buzbee, *Brownfields, Environmental Federalism, and Institutional Determinism*, 21 WM. & MARY ENVTL. L. & POL'Y REV. 1, 1 (1997); Daniel C. Esty, *Revitalizing Environmental Federalism*, 95 MICH. L. REV. 570 (1996).

our regulatory framework to better equip it to deal with new challenges. Perhaps. But what we have sacrificed in efficiency, we may have gained in experimentation. Although the counterfactual is impossible to assess with confidence, we have argued that the three-model system may be producing more (and underappreciated) policy innovation than would occur under a single, national approach. At a minimum, we argue, the diversity inherent in the three-model system has, when combined with directed federal policy nudges and subsidies, allowed for different experiments across different kinds of states and across different aspects of the machine than we would expect to see under a more uniform approach. In a very real way, then, the structure of federalism at the heart of the U.S. system of electricity regulation, and the diversity and experimentalism it has enabled, may be promoting rather than diminishing certain national policy goals—a recognition that animates much of the EPA's Clean Power Plan with its embrace of state autonomy.

Basic principles of public utility law and, specifically, the practice of PUCs in designing and setting rates have been central to the innovations we describe. All of which suggests that we may finally be at a place where we are able to catch up with and realize the value of the experimentalist impulse that was at the heart of an earlier, more expansive concept of public utility but that has lain dormant for so long. We need this creative force now more than ever as we grapple with the need to transform the most complex machine ever built into something vastly cleaner, more distributed, and more interactive. Ratemaking, and the innovation it enables, must be front and center in that effort.