ARTICLES

Outsourcing Electricity Market Design

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A basic principle of virtually every regulation to improve grid reliability and reduce power sector emissions is that market participants change their behavior when regulations make it more expensive to engage in socially harmful activities. To give a concrete example, a carbon tax assumes that increasing the costs of emitting carbon dioxide will lead market participants to reduce energy consumption and switch to less carbon-intensive resources.

But this assumption does not apply to large parts of the electricity industry, where investor-owned utilities are often able to pass the costs of climate and reliability rules on to captive ratepayers. The underlying problem, I argue, is that the U.S. legal system outsources investment and market design decisions to private firms that will be financially harmed if state and federal regulators pursue deep decarbonization or take ambitious steps to improve grid reliability. At the state level, this occurs because utilities propose new infrastructure in integrated resource plans that authorize cost recovery from captive customers. At the federal level, this occurs because the Federal Power Act gives incumbent utilities "filing rights" that authorize them to submit, or "file," regulations and rates related to their assets. Utilities use their filing rights both to propose favorable market rules and to design governance structures that allow them to control the multimember organizations that plan grid infrastructure and ensure resource adequacy. Given that regulatory environment, it is little surprise that incumbent utilities design electricity market rules that counteract climate and reliability regulations. These observations underscore that structural changes such as full corporate unbundling, market liberalization, and aggressive governance reforms are needed to make climate and reliability policies more effective and easier to administer.

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INTRODUCTION

Regulations are effective to the extent that they influence incentives. This is a basic principle of economics. It turns out, however, that electricity market participants are often indifferent to regulatory costs, in large part because of laws and governance arrangements that allow them to pass environmental costs on to customers who are unable to adjust their behavior in response to price increases. Consider the following examples:

1. A carbon tax is supposed to reduce emissions by increasing the costs of generating electricity from fossil resources. But many generators are subject to fuel adjustment clauses that allow them to pass their fuel costs—including the costs of a carbon tax—on to captive ratepayers.[1]
2. Clean energy subsidies are supposed to encourage carbon-free resources to enter the market. But incumbent utilities that control the process for siting and planning transmission also own electric generators. They refuse to build

[1] *See infra* Part II.

transmission lines that would expose their generating units to competition from wind and solar.[2]

3. New technologies such as storage, grid enhancing technologies, and smart meters could improve grid reliability, reduce electricity prices, and reduce emissions. But grid operators often place restrictions on energy efficiency programs, limit new technologies' ability to participate in wholesale markets, and overcompensate fossil resources that are not able meet their reliability commitments.[3]

Historically, most economists have argued that a carbon tax is the optimal way to reduce power sector emissions. Recently, however, an increasing number of scholars and policymakers have recognized that a multipronged approach may be a politically feasible way to achieve rapid emissions reductions.[4] As a result, future climate action will likely consist of a combination of carbon prices,[5] subsidies for clean energy and storage,[6] and liability rules that penalize firms for failing to meet climate or reliability mandates.[7] All these policies seek to align firms' financial

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2 *See infra* Part IV.

3 *See infra* Part III.

4 *See, e.g.*, Severin Borenstein & Ryan Kellogg, *Carbon Pricing, Clean Electricity Standards, and Clean Electricity Subsidies on the Path to Zero Emissions* 2–3 (Nat'l Bureau of Econ. Rsch., Working Paper No. 30263, 2022):

> Most prior comparisons of [various climate policies] have focused on the economic efficiency of outcomes and have overwhelmingly concluded that pricing carbon results in the greatest efficiency, with mandating clean energy shares then generally regarded as more efficient than subsidizing clean energy. . . . We show that the large pre-existing departures of retail electricity prices from efficient levels at least partially undercut the presumed efficiency advantage of pricing carbon.

5 Parts of the country already put a price on carbon dioxide. *See, e.g.*, CAISO, EIM GREENHOUSE GAS ENHANCEMENTS, 2ND REVISED DRAFT FINAL PROPOSAL 3 (2018) (describing greenhouse gas pricing in California and proposed reforms); *Allowance Prices and Volumes*, REG'L GREENHOUSE GAS INITIATIVE, https://perma.cc/KG6W-3FF7 (summarizing prices of emissions allowances in RGGI). Other areas are considering carbon pricing. *See generally* NATALIE TACKA, APPLIED INNOVATION CARBON PRICING SENIOR TASK FORCE, PJM, CARBON PRICING AND LEAKAGE MITIGATION STUDY COMPARISONS (2021).

6 *See LSE Obligations*, N.Y. STATE ENERGY RSCH. & DEV. AUTH. (2023), https://perma.cc/VYV2-25AC (summarizing renewable-energy credits and zero-emissions credits in New York state); *By the Numbers: The Inflation Reduction Act*, THE WHITE HOUSE (Aug. 15, 2022), https://perma.cc/2UNU-GUUW (summarizing Inflation Reduction Act (IRA) subsidies).

7 *See, e.g.*, Nat'l Food Stores, Inc. v. Union Elec. Co., 494 S.W.2d 379, 381–83 (Mo. Ct. App. 1973) (explaining that utilities must take "reasonable care" to prevent outages and to avoid undue harm to customers); Bearden v. Lyntegar Elec. Coop., Inc. 454 S.W.2d 885, 887 (Tex. Civ. App. 1970) ("While a public utility is not an insurer of continuous service, it will be liable for damages which result from its negligence."); *see also*

incentives with the social costs of extracting, producing, and consuming electric energy. They all therefore assume that energy markets are complete (enough) such that regulated parties bear the costs of regulatory interventions.

A complete market is one in which it is possible to exchange every conceivable good and service.[8] An incomplete market is one in which it is impossible to exchange certain goods and services because there is no market in which to trade.[9] As the regulations described above show, electricity markets are characterized by regulations, jurisdictional tensions, and governance arrangements that prevent willing buyers and sellers from exchanging goods. The most obvious example is rate regulation, where an administrative agency protects incumbents from competition and determines which resources will be constructed. Rate regulation is a source of market incompleteness because it prevents customers from contracting for cheaper or cleaner or more reliable power.

Scholars and policymakers have long expressed concern that market incompleteness prevents wholesale electricity markets from creating sufficient financial incentives to support the optimal level of investment in new generating capacity. Typically, the concern is that energy prices are too low, and that reforms to mitigate market power diminish incentives to invest in new generating capacity.[10] The economics literature refers to this as electricity markets' "missing money" problem.[11]

KEN COSTELLO, NAT'L REGUL. RSCH. INST., SHOULD PUBLIC UTILITIES COMPENSATE CUSTOMERS FOR SERVICE INTERRUPTIONS? 10–20 (2012) (summarizing state laws requiring that utilities compensate customers for service disruptions).

8 Market incompleteness exists when it is not possible for market participants to perfectly transfer risk. Bankruptcy, for example, allows buyers to avoid fully performing their contractual obligations upon default, which reduces buyers' incentive to hedge. *Cf.* Kenneth J. Arrow, *Limited Knowledge and Economic Analysis*, 64 AM. ECON. REV. 1, 8 (1974) ("[Under the laws of bankruptcy,] there is no way to ensure complete enforceability [of contracts]. An individual may make a contract which he cannot in fact fulfill."). *See generally* Kenneth J. Arrow & Gerard Debreu, *Existence of an Equilibrium for a Competitive Economy*, 22 ECONOMETRICA 265 (1954).

9 *See generally* Arrow & Debreu, *supra* note 8.

10 *See* THOMAS OLIVIER-LEAUTIER, IMPERFECT MARKETS AND IMPERFECT REGULATION: AN INTRODUCTION TO THE MICROECONOMIC AND POLITICAL ECONOMY OF POWER MARKETS 99–100 (2018). Others have explored issues that arise when firms have market power or when regulations apply only to a subset of the industry. *See generally, e.g.*, Meredith L. Fowlie, *Incomplete Environmental Regulation, Imperfect Competition, and Emissions Leakage*, 1 AM. ECON. J.: ECON. POL'Y 72 (2009).

11 *See* Peter Cramton & Steve Stoft, *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem* 8–11 (MIT Cent. For Energy & Envtl. Pol'y Rsch., Working Paper No. 06-007, 2006);

But market incompleteness is a more pervasive feature of electricity markets than the academic literature suggests. A variety of rules governing economic dispatch of power plants prevent firms and customers from trading risks associated with generating, operating, and transmitting electric energy on the bulk power system. These rules do not simply reduce investment incentives. They also render climate and reliability policies ineffective.[12]

This Article describes how different sources of market incompleteness operate at cross-purposes with climate and reliability rules. Consider, for example, the effect a carbon tax has on a generator with a fuel adjustment clause (also known as a fuel rider). Fuel adjustment clauses are provisions in utility tariffs that allow utilities to pass their fuel costs on to captive ratepayers.[13] They are a source of market incompleteness because they create constraints on the bundle of goods that market participants can exchange. When a fuel adjustment clause allows a utility to pass its fuel costs on to ratepayers, a carbon tax that attaches to physical gas or coal—as opposed to the electricity generated from gas- and coal-fired power plants—has little effect. The costs of the tax are borne by ratepayers, who are typically prohibited from contracting with alternative providers.[14]

This and other electricity market rules that counteract climate and reliability policies are symptomatic of a deeper issue,

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Paul L. Joskow, *Competitive Electricity Markets and Investment in New Generating Capacity* 3 (MIT Cent. For Energy & Envtl. Pol'y Rsch., Working Paper No. 06-009, 2006).

12 For analyses of specific sources of incompleteness and their implications for climate and reliability in energy markets, see generally Joshua Macey & Jackson Salovaara, *Bankruptcy as Bailout: Coal Company Insolvency and the Erosion of Federal Law*, 71 STAN. L. REV. 897 (2019) [hereinafter Macey & Salovaara, *Bankruptcy as Bailout*]; Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 U. PA. L. REV. 1181 (2020) [hereinafter Macey & Salovaara, *Rate Regulation Redux*]; Jacob Mays, David P. Morton & Richard P. O'Neill, *Asymmetric Risk and Fuel Neutrality in Electricity Capacity Markets*, 4 NATURE ENERGY 948 (2019); Jacob Mays, *Missing Incentives for Flexibility in Wholesale Electricity Markets*, 149 ENERGY POL'Y, Feb., 2021, at 1, 1 [hereinafter Mays, *Missing Incentives*]); Han Shu & Jacob Mays, *Beyond Capacity: Contractual Form in Electricity Reliability Obligations*, 126 ENERGY ECON. Oct. 2023, at 1, 1; Jacob Mays & Joshua C. Macey, Accreditation, Performance, and Credit Risk in Electricity Capacity Markets (Sept. 2023) (unpublished manuscript) (on file with author) [hereinafter Mays & Macey, Accreditation, Performance, and Credit Risk] ; Jacob Mays, Michael T. Craig, Lynne Kiesling, Joshua C. Macey, Blake Shaffer & Han Shu, *Private Risk and Social Resilience in Liberalized Electricity Markets*, 6 JOULE 369 (2022).

13 *See Fuel Adjustment Clauses and Other Cost Trackers*, ELEC. CONSUMERS RES. COUNCIL, https://perma.cc/PP42-GDKT; *see also infra* Part II.B.

14 *See* 21ST CENTURY POWER P'SHIP, AN INTRODUCTION TO RETAIL ELECTRICITY CHOICE IN THE UNITED STATES 1 (2017) ("As of 2017, 13 U.S. states and the District of Columbia have fully restructured retail electricity markets.").

which is that the United States has largely outsourced electricity market design decisions to investor-owned utilities—many of which would take significant losses if the United States reduced power sector emissions or made aggressive investments in improving grid reliability.[15] There are two reasons incumbent utilities are positioned to develop market rules and make investment decisions that undermine climate policies. Both are the direct result of the peculiar legal arrangements that govern U.S. electricity production. The first is that the current approach to regulating electric utilities gives incumbent firms authority to unilaterally file tariffs with state and federal regulators in which the incumbent proposes investments and defines the terms and conditions of electricity service.[16] At the state level, this occurs through integrated resource planning. These plans are subject to review by state and federal regulators, but utilities nevertheless propose which resources are constructed and calculate the costs of meeting future demand.[17] In these rate-regulated regions, financial incentives to decarbonize are effective only to the extent that utilities are willing (or forced) to incorporate these incentives in resource planning.

At the federal level, this occurs because the Federal Power Act[18] (FPA), like state resource planning, assumes that investment decisions will be made by rate-regulated firms. Under the FPA, "every public utility shall file with the [Federal Energy Regulatory] Commission . . . schedules showing all rates and charges for any transmission or sale . . . and the classifications, practices, and regulations affecting such rates and charges."[19] The FPA thus puts the Federal Energy Regulatory Commission (FERC) in a reactive position. FERC reviews those tariffs to make

[15] In addition to the governance challenges described in this paper, incumbents also influence the North American Electric Reliability Organization (NERC): the member-owned cooperative charged with developing reliability standards for the bulk electric system. *See* Joshua C. Macey, Shelley Welton & Hannah J. Wiseman, *Grid Reliability in the Electric Era*, 41 YALE J. ON REGUL. 164, 189–204 (2024).

[16] *See* 16 U.S.C. § 824a(a) (directing FERC to "promote and encourage" the "voluntary interconnection and coordination" among electric utilities); 824d(c)–(d); *see also infra* Part I.B.

[17] In markets that continue to be rate regulated, utilities develop resource plans for both generation and transmission. In restructured markets, utilities have unilateral authority only to build certain types of transmission. However, as Part III.B shows, this is itself an important source of incompleteness, and utilities in restructured markets are still able to use their filing rights to exert significant control over market rules.

[18] 16 U.S.C. §§ 791–828(c).

[19] 16 U.S.C. § 824d(c).

sure that they are just and reasonable, but as FERC and state regulators have sought to introduce competition to electricity markets, utilities that own legacy assets have used their filing rights to retain a central role in grid governance.[20]

A second problem is that jurisdictional tensions and the lack of administrative capacity create regulatory gaps that utilities exploit to reduce the efficacy of climate and reliability regulations. An example is the process for planning and building new transmission. Deep decarbonization requires significant investment in large, high-voltage transmission lines that are capable of transporting electricity from solar- and wind-rich areas to regions that consume large amounts electric energy.[21] But regulatory gaps allow utilities to build some lines without undergoing meaningful regulatory scrutiny.[22] In the past decade, the percentage of transmission investment that goes towards these local projects has increased from approximately 30% to 80% in some regions.[23] Here, jurisdictional gaps allow some projects to evade regulatory scrutiny. As a result, utilities have been able to use their residual authority to site and plan local projects to circumvent federal requirements that transmission planners engage in regional and interregional planning processes in which new transmission is procured competitively.

I conclude by proposing specific rules that would reduce incompleteness, as well as structural reforms that would mitigate the political economy issues I describe. At a technical level, regulators should continue to remove barriers to entry so that utilities

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20 *See* infra Part III.

21 *See* PAUL DENHOLM, PATRICK BROWN, WESLEY COLE, TRIEU MAI, BRIAN SERGI, MAXWELL BROWN, PAIGE JADUN, JONATHAN HO, JACK MAYERNIK, COLIN MCMILLAN & RAGINI SREENATH, NAT'L RENEWABLE ENERGY LAB'Y, EXAMINING SUPPLY-SIDE OPTIONS TO ACHIEVE 100% CLEAN ELECTRICITY BY 2035, at 43–50 (2022).

22 *See, e.g.*, Summary Statement of Simon Hurd on Behalf of the Cal. Pub. Utils. Comm'n at 3, Tech. Conf. on Transmission Plan. & Cost Mgmt., No. AD22-8-000 (FERC Sept. 16, 2022) ("For the last three years, 63% of the transmission investment by the three largest TOs in the CAISO has been on utility self-approved projects that are not part of either local or regional transmission planning efforts.").

23 *See* Building for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection, 87 Fed. Reg. 26,504, 26,513 (proposed May 4, 2022) [hereinafter FERC, Building for the Future]:

> The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities. For example, transmission investment to resolve local needs accounted for almost 80% of total transmission investment in MISO from 2018 to 2020. Similarly, in PJM, about two-thirds of the total transmission investment in the region went to resolving local needs.

are compensated for the services they provide. At a structural level, regulators should continue to push for market liberalization, mandate full corporate unbundling, and encourage governance reforms.[24]

This Article proceeds in five parts. Part I describes connections in the supply chain that lead to incomplete risk trading. It also describes market rules, jurisdictional tensions, and governance issues that empower electric utilities to enact legally binding rules that lead to market incompleteness. Part II considers examples in which utilities use integrated resource plans (IRPs) to reduce the effectiveness of many climate and reliability policies. Part III shows how, when FERC sought to restructure electricity markets in the 1990s and early 2000s, utilities used their filing rights to preserve their control over regional transmission organizations (RTOs), transmission planning entities, and regional reliability entities to design wholesale market rules that protect their financial interests. Part IV focuses on transmission planning to show how, even when prescriptive federal rules would seem to reduce utilities' discretion to counteract reliability and clean energy policies—in other words, when utilities cannot control wholesale markets directly—they nevertheless use their filing rights to exploit jurisdictional gaps and, in doing so, circumvent rules that threaten their financial interests. Part V offers recommendations for reform.

I. Legal and Economic Principles of U.S. Electricity Markets

The U.S. electric grid is often described as "the most complex machine ever made."[25] Grid operators must match supply and demand in real time to prevent cascading blackouts.[26] Utilities constructed this machine piece by piece during the twentieth century. Initially, vertically integrated firms built infrastructure to meet their service territories' needs. Although regulators in much

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24 Energy law scholar Shelley Welton has reached a similar conclusion about the limits of the for-profit model in the electricity sector. *See* Shelley Welton, *Public Energy*, N.Y.U. L. REV. 267, 270 (2017) ("This Article argues that climate change complicates the traditional assumption that privately owned electric utilities, driven by profit motives and cabined by regulatory oversight, can most effectively and efficiently run our electricity system.").

25 *See, e.g.*, PHILLIP F. SCHEWE, THE GRID: A JOURNEY THROUGH THE HEART OF OUR ELECTRIFIED WORLD 1 (2007).

26 *See How PJM & Generators Continually Balance the Grid*, PJM LEARNING CTR., https://perma.cc/D56Q-LLA5.

of the country have restructured the generation component of electricity markets, utilities' enduring control over market design and investment decisions is rooted in that history.

A. The Economic Structure of Wholesale Energy Markets

There are four steps in the electricity supply chain. The first step is the acquisition of fuel such as coal, gas, or solar radiation.[27] The second step is electricity generation, whereby fuel is transformed into electricity. The third step is the transmission of electricity over large distances to reach consumers. After electricity is generated, the transmission system moves bulk power from generation facilities to areas that consume electric power. The last step is the distribution system, which involves "stepping down" the voltage of electricity so that it can be safely delivered to consumers.[28]

Electricity markets in the United States are the product of the country's long history with cost-of-service rate regulation.[29] Rate-regulated utilities are protected from competition and subject to price controls.[30] In the early 1900s, policymakers treated every part of the electricity supply chain as a natural monopoly.[31] Utilities were vertically integrated and enjoyed a monopoly over all parts of electricity production, including the generators that supplied electricity, the transmission lines that moved bulk power to demand centers, and the distribution system that

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27 For fossil fuels, this first step is elaborate. For oil and gas, for example, it includes: (a) exploration, where fuel such as oil is extracted from the ground; (b) development of wells or construction of mines; (c) the production process by which the fuel is extracted from the ground; (d) a processing phase in which certain components are removed from the fuel; (e) transportation of the fuel to a refinery; (f) a refining process by which crude oil is converted into products that can be used for heating, electricity generation, and transportation; (g) a distribution process whereby those products are transported to areas where they can be used or sold; and (h) a retailing process by which fuel is sold to end-users, who typically burn the fuel to produce energy for heating, electricity generation, or transportation. *See Fossil Fuel Facts*, AM. PETROLEUM INST., https://perma.cc/UZN5-73Q2.

28 *See* FERC, ENERGY PRIMER: A HANDBOOK FOR ENERGY MARKET BASICS 46–61 (2020) [hereinafter FERC, ENERGY PRIMER].

29 *See* David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 767–69 (2008).

30 *See* ALFRED E. KAHN, THE ECONOMICS OF REGULATION 25–32 (1970); 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 geographic area . . . is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market.").

31 *See* KHAN, *supra* note 30, at xi.

delivered it to consumers. Regulators set rates to prevent utilities from abusing their monopolies.[32]

Toward the end of the twentieth century, regulators in much of the country gradually introduced competition to the electricity generation component of the supply chain.[33] Today, there are (roughly speaking) two ways of compensating electric generators.[34] In approximately one-third of the country, including the Southeast and Pacific Northwest, state public utility commissions (PUCs) continue to set generators' revenues through rate regulation.[35] In those regions, vertically integrated utilities control generation, transmission, and distribution in their service areas. PUCs review utilities' resource portfolios and determine the price that utilities can charge their ratepayers. Utilities continue to be protected from competition, and rates continue to be set in periodic ratemaking proceedings.[36]

The rest of the country has restructured electricity sales to encourage competitive markets for generation. In these areas, a grid operator, often known as an RTO, manages the day-to-day dispatch of electric energy.[37] RTOs are nonprofit, member-owned entities that: (i) run energy market auctions to determine which generators are dispatched (sell electricity) in real time; (ii) oversee regional transmission planning and cost allocation; and (iii) operate transmission lines to make sure supply and demand

32 *See Jersey Cent. Power & Light Co.*, 810 F.2d at 1189 (Starr, J., concurring).

33 *See* Macey & Salovaara, *Rate Regulation Redux*, *supra* note 12, at 1197–1204.

34 *See* Paul L. Joskow, *The Difficult Transition to Competitive Electricity Markets in the U.S.* 5–8 (MIT Ctr. For Energy and Envtl. Pol'y Rsch., Working Paper No. 03-008, 2003).

35 *See Deregulated Energy Markets*, ELECTRICCHOICE.COM (last updated June 2023), https://perma.cc/Z9A8-WJSS.

36 *See Power Sector Competition in the Southeast*, DUKE NICHOLAS INST. FOR ENERGY, ENV'T & SUSTAINABILITY, https://perma.cc/937H-TW68:

> A rapidly changing power sector presents both challenges and opportunities for vertically integrated utilities, their customers, third-party providers, and state regulators in "cost-of-service" states, such as in much of the Southeast. Under the cost-of-service model, the state grants a monopoly to a vertically integrated utility that is responsible for generating, transmitting, and distributing electricity to consumers in a specific territory. The utility charges state-regulated rates to customers seeking to compensate the utility for its costs plus a return on capital investments. Some of the largest investor-owned utilities in the United States are headquartered in the Southeast under this model.

37 *See* FERC, ENERGY PRIMER, *supra* note 28, at 61 ("Two-thirds of the population of the United States is served by electricity markets run by regional transmission organizations or independent system operators.").

remain perfectly balanced.[38] RTOs also often run reliability auctions to make sure that enough generating capacity is in the market.[39] Load serving entities (LSEs) purchase electricity from generators and pay transmission operators for using transmission lines.[40] State PUCs determine the rates LSEs are allowed to charge ratepayers.[41]

RTOs use a process called "merit order dispatch" to meet demand for electric energy. Merit order dispatch aims to ensure that the lowest-cost electric generators that are available to sell electricity are the ones that do so.[42] Each RTO determines how much energy is needed to meet its region's demand and runs an auction to procure electricity from resources capable of operating at that moment.[43] Generators list the price at which they would be willing to sell electricity.[44] Grid operators start with the cheapest bids and accept bids until they have procured enough supply to meet all the region's demand.[45] All resources that "clear the market" receive the price that was submitted by the highest-priced resource that is needed to meet demand.[46] This is known as the clearing price.

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38 For discussions of RTO governance, see generally Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 CALIF. L. REV. 209 (2021) [hereinafter Welton, *Rethinking Grid Governance*]; Ari Peskoe, *Replacing the Utility Transmission Syndicate's Control*, 44 ENERGY L.J. 547 [hereinafter Peskoe, *Replacing the Syndicate's Control*]. *See also* Daniel E. Walters & Andrew N. Kleit, *Grid Governance in the Energy-Trilemma Era: Remedying the Democracy Deficit*, 74 ALA. L. REV. 1033, 1036 (2023) [hereinafter Walters & Kleit, *Grid Governance*] (describing RTOs as "obscure, esoteric, and clubbish entities"); Joel B. Eisen & Heather E. Payne, *Rebuilding Grid Governance*, 48 BYU L. REV. 1057, 1059–67 (2023); Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 558 (2007).

39 *See* CAPACITY MKT. & DEMAND RESPONSE OPERATIONS, PJM, MANUAL 18: PJM CAPACITY MARKET 99–134 (2023).

40 *See Glossary*, PJM GLOSSARY, https://perma.cc/U2AP-DEL2 (defining "Load Serving Entity").

41 *See* FERC v. Elec. Power Supply Ass'n, 577 U.S. 260, 265 (2016) (explaining that the FPA "places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale'—most notably, any retail sale—of electricity").

42 *See How Resources Are Selected and Prices Are Set in the Wholesale Energy Markets*, ISO-NE, https://perma.cc/M7XQ-YGUX [hereinafter *How Resources Are Selected*].

43 Customers can also participate in demand-response programs, in which they offer to reduce demand in exchange for being compensated at the wholesale price. *See* F.E.R.C., Demand Response Compensation in Organized Wholesale Energy Mkts., 76 Fed. Reg. 16,658, 16,659 n.2 (Mar. 24, 2011) (codified at 18 C.F.R. § 35.28(b)(4)).

44 *See How Resources Are Selected*, *supra* note 42.

45 *See id.*

46 *See id.*

To illustrate this process, imagine that there are four generators in a market—solar that offers to sell electricity for $0 per megawatt-hour (MWh), hydro that offers to sell electricity for $10 per MWh, a combined-cycle gas generator that offers to sell electricity for $25 per MWh, and a coal-fired power plant that offers to sell electricity for $40 per MWh. When only three resources are needed to meet demand, then the grid operator sends dispatch instructions to the three cheapest resources—the solar, hydro, and gas. The coal-fired power plant does not operate. The three resources that are dispatched each receive the market clearing price, which was $25 per MWh. If, later in the day, demand increases and the coal-fired power plant is now needed, then all four plants are dispatched. Each would then receive $40 per MWh.

In theory, generators can be expected to bid their marginal costs. If it costs a gas-fired power plant $25 per MWh to operate, then that generator will not bid $24 per MWh, because doing so could result in it being forced to sell electricity at a loss. It will also not bid $26 per MWh, because doing so would expose it to the risk of not being dispatched (and thus not earning a profit) if a competitor sets the clearing price by bidding $25.50. Note that this assumes reasonably competitive markets.

One of the challenges in administering electricity markets is making sure that enough generators enter and remain in the market to meet peak demand: the highest electrical power demand in a given period of time.[47] Demand for electric energy peaks in the summer and winter.[48] When generation is rate regulated, regulators make sure that there is enough capacity by allowing utilities to recover the costs of maintaining adequate reserves to meet peak demand.[49] In restructured markets, however, the market itself must provide sufficient revenue so that generators that operate only a few times a year (or a few times every few years) are able to cover their fixed and operating costs.

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[47] *See* Cramton & Stoft, *supra* note 11, at 3 ("[T]he central problem of resource adequacy is to restore the missing money that prevents adequate investment in generating capacity.").

[48] Jason Donev, *Peaking Power*, ENERGY EDUC., https://perma.cc/47WM-5PML.

[49] *See* JUDITH WILLIAMS JAGDMAAN, JOHN W. BETKOSKI, III, TALINA R. MATHEWS, ANN RENDAHL, MATTHEW SCHUERGER, TED J. THOMAS & ELLIOTT J. NETHERCUTT, NAT'L ASS'N OF REGUL. UTIL. COMM'RS, RESOURCE ADEQUACY PRIMER FOR STATE REGULATORS 57 (2021) [hereinafter JAGDMAAN ET AL., RESOURCE ADEQUACY PRIMER] ("Most state commissions allow each jurisdictional utility to independently establish its RA [resource adequacy] method through integrated resource plans (IRPs) or other planning or modelling processes. Depending on its statutory authority, the state commission may approve or simply acknowledge the IRP, and thus the RA methodology, of a utility.").

Under certain assumptions, energy markets create adequate financial incentives to ensure that there is enough generating capacity to meet peak demand.[50] While most generators will bid their marginal costs, peaking plants, which are plants that operate primarily during scarcity events (these units occupy the right tail of the supply curve), are able to submit energy market bids above their marginal costs.[51] Because there are fewer reserves capable of supplying electricity during scarcity events, peaking plants are able to bid above their marginal costs without worrying that another resource will underbid them.[52] Peaking plants are therefore in a position to submit very high energy market bids. In theory, the inframarginal rents they make during these periods provide a sufficient financial incentive to keep them in the market.[53]

A challenge with a market that relies on high energy prices to meet its resource adequacy needs is that it becomes vulnerable to market power abuses. Regions that rely primarily on energy market prices for resource adequacy have historically experienced high prices and shortages as resources make strategic bids to manipulate the energy market price. Energy market manipulation was perhaps most notable in California in the early 2000s, when firms withheld supply to artificially elevate the price of

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[50] *See* Severin Borenstein, *Understanding Competitive Pricing and Market Power in Wholesale Electricity Markets*, 13 ELEC. J., July 2000, at 49, 52:

> In a competitive market, this process of entry and exit occurs until, in long-run equilibrium, all generators in the market are able to cover their fixed costs and no other generator could enter and cover its fixed costs at the current market prices. There is no economic argument for the necessity of market power to ensure the viability of the industry.

[51] *Cf. id.* But the conditions Professor Severin Borenstein described do not seem to apply in the real world, and most scholars today acknowledge that market power makes it difficult to administer an energy-only market without leaving the market vulnerable to market power abuses. *See, e.g.*, Anna Creti & Natalia Fabra, *Supply Security and Short-Run Capacity Markets for Electricity*, 29 ENERGY ECON. 259, 262 (2006) (citations omitted):

> The PJM Market Monitoring Unit (henceforth, MMU) reports that the functioning of the capacity markets has been competitive in 1999 and 2002 . . . but 2000 and 2001 have witnessed several attempts to exercise market power. In this respect, the MMU has asserted that "market power remains a serious concern given the extreme inelasticity of demand and high levels of concentration in capacity credit markets. Market power is structurally endemic to PJM capacity markets and any redesign of capacity markets must address market power."

[52] *See* David Newbery, *Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors* 3 (Univ. of Cambridge Energy Pol'y Rsch. Grp., Working Paper No. 1508, 2015).

[53] *See id.*

electric energy, and market manipulation has continued to present a regulatory challenge for the past twenty years.[54]

Since regulators introduced competition to electricity generation, economists and policymakers have worried about how to mitigate market power abuses while still providing adequate financial incentives to meet the country's electricity needs.[55] Concern about market power abuses has caused every grid operator in the United States to set an upward limit on the price of electric energy.[56] For the past twenty years, the Electric Reliability Council of Texas (ERCOT), which is the grid operator in most of Texas, has been the only RTO to rely primarily on extreme scarcity pricing to secure resource adequacy. Before Winter Storm Uri, Texas allowed prices to reach $9,000 per MWh.[57] Texas addressed resource adequacy concerns by assuming that the potential to profit during scarcity events would induce generators to make whatever investments were needed to keep the lights on.[58]

Outside of Texas, grid operators have developed alternative mechanisms to ensure resource adequacy while mitigating market power abuses.[59] While offer caps are needed to prevent market

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54 *See* David B. Spence & Robert Prentice, *The Transformation of American Energy Markets and the Problem of Market Power*, 53 B.C. L. REV. 131, 154–59 (2012).

55 *See generally, e.g.*, Mays, *Missing Incentives*, *supra* note 12 (discussing undercompensation for flexible resources); Michael Hogan, *Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System*, 30 ELEC. J., Jan. 2017, at 55 (discussing the relationship between the missing money problem and renewables).

56 *See* MICHAEL HOGAN, ASSISTANCE PROJECT, HITTING THE MARK ON MISSING MONEY: HOW TO ENSURE RELIABILITY AT LEAST COST TO CONSUMERS 9 (2016):

> Where there are concerns about whether the market is sufficiently competitive to prevent abuses, the risk for missing money can also arise from administrative measures intended to correct for or prevent market actors from taking advantage of a dominant market position. Such measures most commonly take the form of caps limiting market prices.

57 *See* Emily Foxhall, *State Regulators Approve Controversial Texas Electricity Market Reform*, TEX. TRIB. (Jan. 19, 2023), https://perma.cc/F75C-TZXJ.

58 *See* PUB. UTIL. COMM'N OF TEX., REVIEW OF THE ERCOT SCARCITY PRICING SYSTEM: PROPOSAL FOR ADOPTION FOR AMENDMENTS TO 16 TAC § 25.505, PROJECT NO. 52631 1 (2021) (revising ERCOT's offer cap from $9,000 per MWh to $5,000 per MWh).

59 *See* Natalia Fabra, *A Primer on Capacity Mechanisms*, 75 ENERGY ECON. 323, 323–29 (2018); *Capacity Market (RPM)*, PJM, https://perma.cc/D9DH-N5GL (stating that PJM's RPM "ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future"); *Installed Capacity Market (ICAP)*, NEW YORK ISO, https://perma.cc/H5MM-LQKX ("The New York Installed Capacity [ ] market serves to maintain reliability of the bulk power system by procuring sufficient resource capability to meet expected maximum energy needs plus an Installed Reserve Margin (IRM)."); *Forward Capacity Market*, ISO NEW ENGLAND, https://perma.cc/C4BC-UC4F ("The Forward Capacity Market (FCM) ensures that the

manipulation, they can also undermine grid reliability by preventing markets from creating sufficient financial incentives to induce generator entry or to prompt generators to invest in preparedness for extreme events. Various resource adequacy mechanisms have emerged to solve the missing money problem.[60] RTOs in the East Coast and parts of the Midwest have developed capacity markets to make sure that they have enough capacity to meet peak demand.[61] Capacity markets compensate generators for making themselves available to sell electricity.[62] Generators that clear the capacity auction are compensated even if they do not sell electricity. California and other parts of the country do not use centrally administered capacity markets.[63] They instead place a resource adequacy obligation on LSEs: the firms that purchase electricity to sell to consumers.[64] In these markets, LSEs can build their own resources or enter bilateral transactions with resources that are needed for resource adequacy.[65]

The economics literature has long recognized that offer caps are a source of market incompleteness because they set an upward limit on scarcity prices.[66] Buyers who are willing to pay more for reliable service are unable to do so even if they could find

New England power system will have sufficient resources to meet the future demand for electricity.").

60 *See, e.g.*, Fabra, *supra* note 59, at 324 ("Providing adequate investment incentives while at the same time mitigating market power requires the use of capacity payments in conjunction with price caps since price caps alone would mitigate market power but would result in poor investment incentives."); Cramton & Stoft, *supra* note 11, at 4 (explaining that "the missing money must be restored without reintroducing the market power problems currently controlled by price suppression").

61 *See* PJM Interconnection, L.L.C., 117 F.E.R.C. ¶ 61,331, at p. 62,653 (2006) (approving PJM's capacity market, known as the reliability pricing model, to ensure that the mid-Atlantic region "has sufficient generating capacity to meet its reliability obligations").

62 *See, e.g.*, *id.* For a critique of how capacity markets are administered in current markets, see generally Mays & Macey, Accreditation, Performance, and Credit Risk, *supra* note 12.

63 *See* Cal. Pub. Util. Comm'n, *Resource Adequacy Homepage*, CA.GOV, https://perma.cc/VQU5-K3FZ ("The Commission's RA [Resource Adequacy] policy framework—implemented as the RA program—guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed.").

64 *See, e.g.*, CAL. PUB. UTIL. CODE § 380(c) (Deering 2023) ("Each load-serving entity shall maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves.").

65 *See* JAGDMAAN ET AL., RESOURCE ADEQUACY PRIMER, *supra* note 49, at 47–48.

66 *See* TODD S. AAGAARD & ANDREW N. KLEIT, ELECTRICITY CAPACITY MARKETS 37 (2022); Paul Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets,* 38 RAND J. ECON. 60, 70–74 (2007).

a seller willing to enter the market to sell at that price. The concern is that offer caps create a missing money problem by limiting the revenue available in energy markets, which undermines resources' incentives to make themselves available when electricity is most needed. Economists and policymakers have traditionally focused on how to value electricity at various periods of time and on the optimal design of resource adequacy markets to provide a sufficiently large financial incentive to meet the region's energy needs.

But as the rest of this Article shows, the legal and institutional framework that governs energy markets introduces additional sources of incompleteness. In addition to revenue shortfalls for generating capacity, investor-owned utilities draft rules that allow them to pass the financial incentives created by many climate and reliability policies on to captive ratepayers.

B. Filing Rights and FERC's Authority to Reform the Electricity Sector

First, it is important to describe the legal rules, jurisdictional tensions, and governance arrangements that empower market participants to introduce incompleteness when drafting tariffs and making planning decisions. While utilities are regulated both at the state level by PUCs and at the federal level by FERC,[67] they are themselves responsible, in the first instance, for making investment decisions and designing electricity market rules.[68] As the D.C. Circuit has explained, FERC and state PUCs play "an

67 *See* Matthew R. Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1362–63 (2021); *see also* DANIEL SHEA, NAT'L CONF. OF STATE LEGISLATORS, ELECTRICITY MARKETS: A PRIMER FOR STATE LEGISLATORS 3 (2022) [hereinafter SHEA, ELECTRICITY MARKETS].

68 *See* 16 U.S.C. § 824d(d):

> [N]o change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect.

See also Atl. City Elec. Co. v. FERC, 295 F.3d 1, 10 (D.C. Cir. 2002) (explaining that section 205 and 206 of the FPA "are simply parts of a single statutory scheme under which all rates are established initially by the [public utilities], by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful") (alteration in original) (emphasis omitted) (quoting United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 341 (1956)).

essentially passive and reactive role" in developing energy market rules.[69]

1. Filing rights.

In the electricity industry's early years, regulators gave utilities exclusive franchises.[70] Utilities would file tariffs or propose resource plans that would allow them to meet future demand, and propose rates that would allow them to cover their costs and earn a return.[71] These tariffs would describe not only what resources utilities would invest in, but also the terms and conditions of electricity sales.[72] Regulators would review utility tariffs to determine whether those investments were prudent. States continue to rely on the IRP process to review retail electricity rates.[73] When utilities perform IRPs, they forecast demand, analyze future risk, and develop a portfolio of assets that will allow them to meet future demand cost effectively.[74] As a result, in large parts of the country, industry determines which resources will be constructed, how much customers will be charged, and when resources retire.

When Congress gave FERC, originally known as the Federal Power Commission, authority to regulate transmission rates and wholesale sales, it appears to have assumed a regulatory model in which utilities, subject to strict regulatory supervision, would continue to make investment decisions and develop energy market rules. The reason utilities draft market rules is that section 205 of the Federal Power Act requires that "every public utility shall file with the Commission . . . schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission."[75] In addition to proposing (and filing with the Commission) the rates they charge, utilities also file "the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services."[76] The FPA defines "public utility" as "any person who owns or

69 City of Winnfield v. FERC, 744 F.2d 871, 876 (D.C. Cir. 1984).

70 *See* FERC, ENERGY PRIMER, *supra* note 28, at 38.

71 *See id.* at 59–60.

72 *See id.*

73 MIDWEST ENERGY EFFICIENCY ALL., INTEGRATED RESOURCE PLANS: CRITERIA FOR AN EFFECTIVE PLANNING TOOL (2020).

74 *See id.*

75 *Id.* § 824d(c).

76 *Id.*

operates facilities subject to the jurisdiction of the Commission."[77] Thus, while FERC regulates wholesale sales and transmission,[78] incumbent utilities have the first say in drafting wholesale market rules.

FERC's primary responsibility is thus to review rates schedules.[79] To that end, Congress instructed FERC to "promote and encourage" the "voluntary interconnection and coordination" of electric utilities. As a result, FERC and state PUCs typically review rates and market rules that are initially drafted by utilities, RTOs, regional reliability entities, and regional transmission planning entities. FERC has authority to make sure that rates are "just and reasonable" and not unduly discriminatory, but it cannot set rates in the first instance.[80] Courts have explained that FERC must accept utility tariffs that fall within a "zone of reasonableness."[81] This is a deferential standard of review. FERC cannot simply impose its preferred market design. It must meet a relatively high burden of showing that utility tariffs are affirmatively problematic. In addition, the D.C. Circuit has held that FERC cannot take away utilities' filing rights.[82]

A lengthy academic literature has shown that incumbents heavily influence RTO decision-making.[83] Utilities' control is most apparent in vertically integrated markets, where incumbent utilities develop resource plans to meet future demand. But in restructured markets, too, FERC and states were required to introduce competition by convincing the firms that owned electricity infrastructure at the time to form voluntary, member-owned organizations. The next three Parts connect specific market rules to utilities' outsized role in grid governance. The central point is that utilities' filing rights have allowed them to shape grid governance even as regulators have moved away from traditional rate regulation.

77 *Id.* § 824(e). "The term 'electric utility company' means any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale." 42 U.S.C. § 16451(5).

78 *See* 16 U.S.C. § 824(b)(1); *see also* Christiansen & Macey, *supra* note 67, at 1371–81; Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEX. L. REV. 399, 408–14 (2016).

79 FERC is supposed to ensure that rates are "just and reasonable" and not "unduly discriminatory." 16 U.S.C. §§ 824d(a), 824e(a).

80 *See* Emera Me. v. FERC, 854 F.3d 9, 19–21 (D.C. Cir. 2017).

81 *See id.* at 22–23.

82 *Atl. City Elec. Co.*, 295 F.3d at 9–11.

83 *See supra* note 38.

Note that this, too, appears to be a result of the history of the electricity industry. Throughout the twentieth century, vertically integrated utilities entered voluntary power pools in which they agreed to trade power with neighboring utilities to keep costs down and improve reliability.[84] If one utility's generation portfolio was unable to meet demand, either due to routine service or a natural disaster or because demand was high, it would often be able to meet demand more reliably and less expensively if it could import power from neighboring regions.

For example, PJM, the grid operator that serves eighty-five million Americans in the mid-Atlantic, originated as a voluntary power sharing arrangement in 1927.[85] The New England Power Pool (NEPOOL) was formed to coordinate transmission planning and support economic dispatch of power in 1971 and was the industry's response to the 1965 Northeast Blackout.[86] NEPOOL, like PJM, arose because incumbent utilities voluntarily chose to coordinate their operations.[87]

For decades, FERC has struggled to convince utilities to adopt governance arrangements that reflect a broad array of interests. For example, when FERC reviewed NEPOOL's membership rules, it expressed concern that "NEPOOL might narrow the basis for wholesale competition," but ultimately concluded that "reduction in cost of service resulting from this new-found coordination is most certainly in the public interest and outweighs any possible reduction in wholesale competition."[88] FERC and states thus built many of today's competitive electricity markets on top of power pools that exist because utilities voluntarily agreed to trade power among themselves.

Because power pools were formed by incumbent utilities, those utilities were able to propose rules and governance

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84 *See, e.g.*, *Atl. City Elec. Co.*, 295 F.3d at 5 (citation omitted):

> The Pennsylvania–New Jersey–Maryland ("PJM") Interconnection is a tight power pool. The PJM power pool—the oldest and largest power pool in the nation—was formed as a voluntary organization comprised of investor-owned utilities that operate their generating and transmission facilities in a coordinated manner so that regional power loads can be met reliably and efficiently. It was formed in 1927, and became a "tight" power pool by operating as a single control area with freeflowing transmission ties in 1956. Under the 1956 operating agreement, the PJM members agreed to place their generating facilities under the control of a central system dispatcher.

85 *See id.*

86 *See About NEPOOL*, NEPOOL, https://perma.cc/BVF8-RNVA.

87 *See id.*

88 New Eng. Power Pool Agreement, 56 F.P.C. 1562, at p. 1587 (1976).

arrangements that preserved their control over the boards that design market rules. In PJM, incumbents control three of the five member committees.[89] In NEPOOL, firms that own generation, transmission, or supply power to the region comprise at least fifty percent of the power pool's voting sectors.[90]

RTOs are only one area where incumbent utilities control electricity market rules. Utilities have taken advantage of the fact that FERC is generally supposed to defer to voluntary coordination to retain some degree of control of seemingly all the private entities that regulate the electricity sector. That includes NERC, the private entity charged with developing reliability standards,[91] as well as regional reliability entities and regional transmission planning entities. For example, the Southeast Reliability Corporation (SERC), a regional entity that develops reliability standards in the Southeast,[92] is governed by utilities that provide generation, transmission, and distribution service in the Southeast.[93] SERC, however, delegates responsibility for maintaining reliability to subregional entities, which are often themselves controlled by the vertically integrated utilities that have a legal monopoly in that service territory.[94] Thus, NERC, a member-owned reliability regulator, delegates some responsibilities to SERC, a member-owned reliability regulator whose members also vote on NERC reliability standards. SERC, in turn, delegates responsibilities to SERC-Southeast and other subregional entities, whose members provide generation, transmission, and distribution services in the Southeast and are also on the boards of SERC and NERC.

A similar story plays out in other reliability regulators, though the particular governance dynamics differ by region.[95] For

89 *Governance*, PJM, https://perma.cc/YV3V-BK7F.

90 *See* NEW ENG. POWER POOL, SECOND RESTATED NEPOOL AGREEMENT 25–30 (2019) [hereinafter NEPOOL, SECOND RESTATED AGREEMENT] (available at https://perma.cc/EUF3-KSQW); *FAQs: Membership*, ISO NEW ENGLAND, https://perma.cc/P83Z-ZPWA.

91 *See* Macey, Welton & Wiseman, *supra* note 15, at 170.

92 SERC, REGIONAL RELIABILITY STANDARDS DEVELOPMENT 4 (2021) [hereinafter SERC, STANDARDS DEVELOPMENT].

93 *See Current Member Listing*, SERC, https://perma.cc/344N-DZPQ.

94 *See, e.g.*, SERC, RELIABILITY PLAN FOR THE SERC SOUTHEASTERN SUBREGION RELIABILITY COORDINATOR 2 (2022) [hereinafter SERC, RELIABILITY PLAN FOR THE SE. SUBREGION].

95 *See, e.g.*, *Membership*, WECC, https://perma.cc/BD2T-WDKU (listing the 321 members of the Western Electricity Coordinating Council); WECC, RELIABILITY ASSESSMENT COMMITTEE CHARTER 1–3 (2022) [hereinafter WECC, CHARTER] (explaining

example, the Midwest Reliability Organization (MRO) is governed by a twenty-three-person partially independent board of directors. Four of the directors are independent, two are "regional directors," and seventeen are stakeholder directors.[96] The independent directors are elected by voting members.[97] While MRO is perhaps more independent than SERC—after all, only seventeen of the twenty-four directors represent outside stakeholders—MRO, like SERC, delegates considerable responsibilities to utilities themselves.[98] These responsibilities include giving utilities discretion to determine which data they will submit in order to help MRO draft reliability reports.

Incumbent utilities also heavily influence transmission planning. Here, too, transmission owners (TOs) have used their filing rights to ensure that they retained control over transmission planning entities. For example, the Southeast Regional Transmission Planning (SERTP), which is responsible for transmission planning process in the Southeast, is controlled by the rate-regulated utilities that provide service in that region.[99] SERTP was formed to comply with Order No. 890's mandate that utilities conduct open and transparent regional transmission planning.[100] Even though FERC Order No. 1000 requires transmission planners to examine regional solutions and conduct competitive procurements for regional transmission lines,[101] the reality is that most planning is conducted in a piecemeal fashion as utilities build transmission to address local needs.

SERTP members submitted their Order No. 1000 compliance filings in February 2013.[102] At the time, FERC found a number of

that WECC's Annual Reliability Assessment is drafted by its Reliability Assessment Committee and how representation on the Reliability Assessment Committee works).

96 *See Board of Directors*, MIDWEST RELIABILITY ORG., https://perma.cc/K9SJ-J6NU.

97 *See id.*

98 *See* MIDWEST RELIABILITY ORG., 2021 ANNUAL REPORT 8 (2021) (stating that "entities willingly share information in order to improve bulk power system reliability" but are not required to disclose Bulk Electric System events or disturbances); *see also Governance and Corporate Matters*, NPCC, https://perma.cc/EL44-6RK5 (explaining that (i) the Northeast Power Coordinating Council is governed by a board of directors consisting of fourteen Stakeholder Directors, two Independent Directors, an Independent Board Chair and the President and CEO; (ii) data used in NPCC reliability assessments derives from member entities; and (iii) subregions use different demand forecast methodologies).

99 SE. REG'L TRANSMISSION PLAN., PJM-SERTP PLANNING PROCESS OVERVIEW 4–5 (2020) [hereinafter SERTP, PLANNING PROCESS OVERVIEW].

100 *Id.* at 4.

101 144 F.E.R.C. ¶ 61,054, at ¶¶ 2–4 (Order on Compliance Filings 2013) [hereinafter SERTRP First Order].

102 *See id.* at ¶ 1.

deficiencies in SERTP's initial proposal, including the scope of the planning region, the definition of transmission facilities covered by Order No. 1000, and the process for becoming a SERTP member.[103] For example, the first SERTP Order No. 1000 compliance filing stated that "a public utility or non-public utility transmission provider that has a[n] . . . obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region" could enroll by simply filling out an application.[104] FERC worried that this requirement would "prohibit an entity that wishes to voluntarily enroll in the SERTP region from doing so, if that entity does not have a statutory or OATT obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region."[105] In other words, only firms that already had an obligation to provide transmission service in the Southeast would be eligible to become SERTP members.

FERC was also concerned that there would not be sufficient opportunity for interested parties to participate in transmission planning,[106] and, more specifically, that SERTP processes would not provide affected parties with information that would be relevant to transmission planning or consider regional solutions to its transmission needs. Order No. 1000 required RTOs to explain how and when they would determine if more efficient or regional solutions were available.[107] Yet FERC found that southern utilities' first Order No. 1000 compliance filing "lack sufficient detail for stakeholders to understand the procedures Filing Parties will use to identify and evaluate at the regional level transmission needs driven by public policy requirements."[108] According to the Commission, the "lack of description regarding how Filing Parties will decide whether to retain a transmission project, remove a transmission project, or select an alternative transmission solution following such reevaluation may allow Filing Parties too much discretion in making this determination."[109]

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103 *Id.* at ¶ 27.

104 *Id.* at ¶ 29.

105 *Id.* at ¶ 29. This issue was resolved when the filing parties removed this requirement in the second filing. *See* 147 F.E.R.C. ¶ 61,241, at ¶ 53 (Order on Rehearing and Compliance 2014) [hereinafter SERTP Second Order].

106 144 F.E.R.C. ¶ 61,054, at ¶¶ 111–19 (Order on Compliance Filings 2013).

107 F.E.R.C. Order No. 1000, Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils., 76 Fed. Reg. 49,842 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1000].

108 144 F.E.R.C. ¶ 61,054, at ¶¶ 112 (2013).

109 *Id.* at ¶ 218.

The Commission's concerns proved prescient. While FERC attempted to push back against SERTP planning rules that gave incumbents undue influence over new transmission investments,[110] today SERTP planning is often criticized for providing minimal opportunity for stakeholder input and appears to simply aggregate each individual utility's local plan.[111] In other words, the utilities that came together to form a regional transmission planning entity develop plans locally, and when they conduct transmission planning, they do so in a way that preserves their complete control over the processes for planning, generation, and transmission.[112]

2. FERC's authority over filing rights.

Even when FERC has tried to reform governance,[113] utilities' filing rights allowed them to insist on the governance roles described above. While FERC nominally requires that RTOs be independent of their owners and reflect a broad array of stakeholder input,[114] current governance arrangements reflect a series of negotiations between FERC and incumbent utilities in which utilities leveraged their filing rights to retain authority over market design decisions. When FERC urged utilities to form RTOs in Orders No. 888 and 2000, it justified what was perhaps the most aggressive federal intervention in the history of U.S. electricity markets by explaining that TOs used their control over

110 *See id.*

111 *See* Comments of the S. Renewable Energy Ass'n, at 22–29, FERC, Building for the Future, 87 Fed. Reg. 26,504 (proposed May 4, 2022), https://perma.cc/2U6F-9XBQ.

112 Here, too, FERC and state regulators have authority to reject preferential tariffs, but again, regulators are in a reactive role and may struggle to identify and remedy every type of market imperfection that undermines climate and reliability rules.

113 A rich academic literature has discussed RTO governance problems. My goal here is to describe the legal rules that have caused these problems. *See also* Welton, *Rethinking Grid Governance*, *supra* note 38; Dworkin & Goldwasser, *supra* note 38; Peskoe, *Replacing the Syndicate's Control*, *supra* note 38. *See also* Walters & Kleit, *Grid Governance*, *supra* note 38, at 1035–40; Eisen & Payne, *supra* note 38, at 1059–70 (2023); Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 U. ILL. L. REV. 1, 44–55 (2014); Hari M. Osofsky & Hannah J. Wiseman, *Dynamic Energy Federalism*, 72 MD. L. REV. 773, 804–19 (2013).

114 *See* F.E.R.C. Order No. 2000, Reg'l Transmission Orgs., 65 Fed. Reg. 810, 857 (Jan. 6, 2000) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2000] ("[W]e emphasize that the common element for all types of RTOs must be that they satisfy the threshold principle that their decisionmaking should be independent of market participants."); *id.* at 850 ("It is the Commission's view that an RTO must be independent of any entity whose economic or commercial interests could be significantly affected by the RTO's actions or decisions. Without such independence, it will be difficult for an RTO to act in a nondiscriminatory manner.").

transmission assets to engage in exclusionary and anticompetitive conduct.[115] FERC required that RTO "governance . . . prevent control . . . by any class of participants."[116]

However, when utilities began to form RTOs in the late 1990s and early 2000s, they repeatedly tried to convince FERC to authorize governance arrangements that would have given them "ultimate control" over the RTO.[117] FERC pushed back against these early proposals by ordering utilities to cede filing rights over transmission rates to RTOs.[118] Utilities sued, and in *Atlantic City Electric Co. v. FERC*,[119] the D.C. Circuit held that utilities cannot be forced to relinquish their filing rights but must do so voluntarily.[120] Then, in 2004, the D.C. Circuit held in *California Independent System Operator v. FERC*[121] that the Commission exceeded its jurisdiction in ordering the California Independent System Operator (CAISO) to adopt a particular process for selecting board members.[122] Since those two decisions, FERC has largely avoided interfering in RTO governance.

After *Atlantic City*, TOs managed to secure concessions from FERC that ensured that they would retain significant control over RTO governance. RTO's section 205 filing rights thus reflect settlements between utilities and RTOs. These settlements give incumbents control in three respects. First, as described above, incumbents are directly involved with voting on RTO decisions. Second, and as discussed in more detail in Part IV, utilities retained authority to file certain rates, particularly over

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115 *See* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667, 682 (D.C. Cir. 2000); F.E.R.C. Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils., 61 Fed. Reg. 21,540, 21,567 (May 10, 1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888]; F.E.R.C. Order No. 888-A, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils., 62 Fed. Reg. 12,274, 12,275–12,277 (Mar. 14, 1997) [hereinafter Order No. 888-A] (1997).

116 Order No. 888, 61 Fed. Reg. at 21,596 ; *see also* Cal. Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395, 397 (D.C. Cir. 2004) ("FERC deems it crucial that an ISO be independent of the market participants.").

117 Atl. City Elec. Co., 77 F.E.R.C. ¶ 61,148, at p. 61,574 (1996); *see also* New Eng. Power Pool, 83 F.E.R.C. ¶ 61,045, at p. 61,260 (1998); New Eng. Power Pool, 86 F.E.R.C. ¶ 61,262, at p. 61,965 (1999); Cent. Hudson Gas & Elec. Corp., 83 F.E.R.C. ¶ 61,352, at p. 62,409 (1998); Cent. Hudson Gas & Elec. Corp., 87 F.E.R.C. ¶ 61,135, at p. 61,540 (1999); Mid-Continent Area Power Pool, 87 F.E.R.C. ¶ 61,074 at p. 61,317 (1999).

118 *See* Pennsylvania-New Jersey-Maryland Interconnection, 81 F.E.R.C., at p. 62,279.

119 295 F.3d 1 (D.C. Cir. 2002).

120 *Id.* at 44.

121 372 F.3d 395 (2004).

122 *Id.* at 398.

transmission. And third, because RTO membership is voluntary, utilities can influence RTO decision-making by threatening to withdraw from the RTO.[123]

These governance challenges are exacerbated by jurisdictional gaps that often allow utilities to make investment decisions without undergoing any regulatory scrutiny. Federal authority to regulate energy was the result of a Supreme Court decision holding that states could not regulate interstate sales of electric energy.[124] FERC regulates interstate sales of electric energy and transmission rates. States retain authority over siting decisions and retail rates, which are sales to end users.[125] While there are compelling reasons to think that the current distribution of jurisdiction serves important policy goals,[126] the implementation of this federalist structure has resulted in regulatory gaps that utilities exploit to make investment decisions that protect fossil resources.[127]

The sources of market incompleteness discussed in the rest of this Article result from one or both these issues. Sometimes, utilities use their filing rights to directly counteract climate policies by developing market rules that protect their investments. At other times, particularly with transmission planning, utilities take advantage of gaps between state and federal regulations to make investments that undermine federal regulations designed to reduce costs, improve reliability, and support state decarbonization goals.

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123 *See* Pennsylvania-New Jersey-Maryland Interconnection, 105 F.E.R.C. ¶ 61,294, at pp. 62,430–31 (2003); Duke Energy Ohio, 133 F.E.R.C. ¶ 61,058, at pp. 61,239–40 (2010). *See also generally* Midwest Indep. Transmission Sys. Operator, Inc., 110 F.E.R.C. ¶ 61,380 (2005); ARI PESKOE, ELEC. L. INITIATIVE, ISO-NEXIT: EXPLORING PATHWAYS FOR A UTILITY'S WITHDRAWAL FROM NEW ENGLAND'S REGIONAL TRANSMISSION ORGANIZATION (2020); Duquesne Light Co., 122 F.E.R.C. ¶ 61,039 (2008); Am. Transmission Sys. Inc., 129 F.E.R.C. ¶ 61,249 (2009).

124 *See* Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).

125 *See* Christiansen & Macey, *supra* note 67, at 1371–76; *see also* Ari Peskoe, *Easing Jurisdictional Tensions by Integrating Public Policy in Wholesale Electricity Markets*, 38 ENERGY L.J. 1, 3–7 (2017); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U.C. DAVIS L. REV. 1783, 1790–91 (2016); Rossi, *supra* note 78, at 408, 412. *See generally* Jim Rossi, *Energy Federalism's Aim*, 134 HARV. L. REV. F. 228 (2021); Joel B. Eisen, *The New (Clear?) Electricity Federalism: Federal Preemption of States' "Zero Emissions Credit" Programs*, 45 ECOLOGY L. CURRENTS 149 (2018); Joel B. Eisen, *Dual Electricity Federalism Is Dead, but How Dead, and What Replaces It?*, 8 GEO. WASH. J. ENERGY & ENVTL. L. 3 (2017).

126 *See* Christiansen & Macey, *supra* note 67, at 1395–1407.

127 *See infra* Part IV.B.

II. INCOMPLETENESS AND RATE REGULATION

The continued use of rate regulation is the most direct way for utilities to pass the costs of climate and reliability regulations on to their ratepayers. Rate regulation can be understood as a source of market incompleteness because it substitutes customer choice with an administrative mechanism for hedging risk. And it is a source of market incompleteness in which utilities determine, in the first instance, what energy infrastructure will be built and who can pay for it. Although generators in most of the country now participate in competitive markets for generation, large regions, including the Southeast and Pacific Northwest, continue to use cost-of-service regulation to procure new generating capacity and to compensate existing suppliers.[128] Even in restructured markets, the transmission and distribution systems continue to use cost-of-service regulation, as do inter- and intraregional gas pipelines that supply fuel to generators. Other parts of the supply chain that use cost-of-service regulation allow utilities to write rules and make investment decisions that pass the costs of climate regulations on to their captive ratepayers.

A. Rate-Basing Climate and Reliability Policy

Vertically integrated utilities in parts of the country where generators remain rate regulated have occasionally been outspoken proponents of carbon pricing. Utilities' support for a carbon price may appear surprising, since regions where generation is rate regulated have the highest levels of power sector emissions in the United States.[129] These utilities are therefore lobbying for a carbon tax or cap-and-trade system that would increase their costs—often significantly.

One possible explanation for utilities' support of carbon taxes is that rate regulation protects them from the financial costs carbon taxes are designed to impose. Utilities' revenues are based on

[128] *See* SHEA, ELECTRICITY MARKETS, *supra* note 67, at 1 ("While close to two-thirds of the electricity demand in the U.S. is served through entities that operate wholesale electricity markets, only around one-third of states have fully restructured their electric sector in a manner designed for competition.").

[129] *See Energy-Related CO_2 Emission Data Tables*, U.S. ENERGY INFO. ADMIN., https://perma.cc/N35H-L852. In fact, 93% of the country's coal capacity is rate regulated. *See* Christian Fong & Sam Mardell, *Securitization in Action: How U.S. States Are Shaping an Equitable Coal Transition*, RMI (Mar. 4, 2021), https://perma.cc/2YE5-X9J7. *See* METIN CELEBI, LONG LAM, JADON GROVE & NATALIE NORTHRUP, BRATTLE GRP., A REVIEW OF COAL-FIRED ELECTRICITY GENERATION IN THE U.S. 4 (2023).

a formula in which a regulator determines what costs a utility should incur and authorizes the utility to recover those costs in retail rates and earn a reasonable profit. To calculate a utility's revenue requirement, regulators calculate the utility's rate base, which typically consists of fixed costs and other capital expenses, multiplies that rate base by an allowed rate of return, and then adds operating expenses.[130]

Rate regulation gives utilities an incentive to spend money wastefully. A utility that increases its costs is entitled to charge higher rates—so long as the regulator deems the costs prudently incurred. For example, a utility that is authorized to spend $1,000 will be able to charge ratepayers $1,090 if regulators authorize a 9% return, whereas a utility that is authorized to spend $2,000 will be able to charge $2,180. Utilities' incentive to increase their costs is known as the Averch-Johnson effect (known colloquially as gold plating).[131] In theory, customers can respond to higher prices by reducing electricity consumption. However, because electricity demand is highly inelastic, customers typically have few, if any, alternative providers with whom to transact. As a result, higher electricity prices lead to relatively little demand reduction in real time. Utilities' exclusive franchises thus protect them from the risk that customers will switch to alternative suppliers.

Without sufficient regulatory oversight, carbon taxes allow utilities to engage in what I call "regulatory gold plating." The carbon tax drives utilities' costs up. But since utilities can recover reasonably incurred costs, they will often be able to pass the costs of carbon taxes on to customers without changing their behavior. Because demand is inelastic and retail rates do not reflect real-time energy prices, the utility can be relatively confident that it will not lose customers when it increases prices to reflect those higher costs.[132]

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130 *See* Darryl Tietjen, *Tariff Development I: The Basic Ratemaking Process*, NAT'L ASS'N OF REGUL UTIL. COMM'RS, https://perma.cc/NZN2-9VTA (briefing for the NARUC/INE Partnership) (on file with author).

131 *See, e.g.*, William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 1 BELL J. ECON. & MGMT. SCI. 162, 162–64 (1970); Alvin K. Klevorick, *The Behavior of a Firm Subject to Stochastic Regulatory Review*, 4 BELL J. ECON. & MGMT. SCI. 57, 57–60 (1974). *See generally* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962).

132 High prices would cause consumers to purchase less capacity when supply is scarce. However, because utility rates in the United States typically do not reflect the real-time price of electricity, changes in retail price do not cause consumption to change to the same extent as would occur if rates better reflected generator costs. For an overview of the

That is not the case in non-rate-regulated markets. By raising the costs of generating power from fossil resources, carbon taxes cause less carbon-intensive generators to be dispatched more frequently than they otherwise would. In restructured markets, when coal-fired power plants pay a carbon tax, they become less likely to clear energy market auctions, since less carbon-intensive resources are now able to provide cheaper electricity than coal-fired generators. The carbon tax shifts the coal-fired generator to the right of the supply curve. In utility markets, by contrast, there are no competitors to take market share. As a result, increased prices do not automatically translate into lower sales.

The law of regulated industries increases utilities' ability to pass compliance costs on to ratepayers. Under U.S. law, utilities are automatically allowed to recover the costs of complying with environmental, reliability, and other wholesale market rules. Courts have repeatedly held that utility franchises are a property right, and that states must permit utilities to recover the costs of complying with state and federal regulatory requirements.[133] PUCs can review utilities' business plans to make sure that the utility has developed a reasonable and prudent approach to complying with state and federal regulations, but they cannot second-guess state and federal legislatures.[134]

But allowing utilities to pass regulatory costs on to ratepayers creates perverse compliance incentives and can operate at cross-purposes with clean energy policies. It is often cheaper for utilities to take precautions to improve reliability or reduce environmental risks before they cause significant harm. Transmission line maintenance, for example, has historically been underfunded despite reducing wildfire risk.[135] That reduces utilities' incentive

effects of retail pricing, see generally Severin Borenstein, *Time-Varying Retail Electricity Prices: Theory and Practice*, *in* ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES 317 (James M. Griffith & Steven L. Puller eds., 2005).

133 *See* Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan., 489 U.S. 493, 498 (1988) (prohibiting the Kansas Corporation Commission from refusing to recover the costs of gas priority rules); Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 960 (1986) (requiring Tennessee regulators to authorize cost recovery for peak pricing rules). *See generally* N. Nat. Gas Co. v. Fed. Power Comm'n, 399 F.2d 953 (D.C. Cir. 1968).

134 *See* Duquesne Light Co. v. Barasch, 488 U.S. 299, 313–14 (1989). There is an argument that, in some circumstances, this is a sensible regulatory approach, since it ensures that firms have sufficient revenues to cover the costs of new regulations. Thus, when the Environmental Protection Agency (EPA) strengthens standards for mercury emissions, or when a state requires utilities to bury transmission lines to reduce wildfire risk, utilities have a legal right to recover those compliance costs.

135 *See* ELEC. SAFETY & RELIABILITY BRANCH, SAFETY & ENF'T DIV., CAL. PUB. UTIL. COMM'N, SED INCIDENT INVESTIGATION REPORT FOR 2018 CAMP FIRE WITH ATTACHMENTS

to act preemptively since they have no assurance that they will be able to recover the costs they incur burying lines or trimming trees. In fact, PUCs have often refused to allow cost recovery when utilities have sought to bury transmission lines.[136] As a practical matter, the evidentiary burden of convincing PUCs to allow utilities to recover the costs of burying transmission lines is likely higher before transmission line failures cause catastrophic wildfires: the wildfire provides strong evidence that additional investments are needed.

Yet once a utility faces a regulatory mandate to improve safety or reduce emissions, it can be confident that it will be able to recover its compliance costs.[137] A utility may therefore be better off financially if it waits to invest in safety or environmental measures—even though it thereby increases the risk of devastating wildfires—and only takes safety or environmental precautions once its PUC has instructed it to do so. This doctrine has proven controversial. In one example, Duke Energy recovered approximately $10 billion in Clean Water Act[138] costs after its failure to properly store coal resulted in a coal ash spill that caused more than eighty deaths and hundreds of cases of lung cancer.[139]

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20 (2018) ("SED concludes that PG&E's transmission inspection and maintenance program prior to the Camp Fire was inadequate to ensure that PG&E's transmission lines . . . were in good condition to allow them to operate in a safe manner."); Russell Gold & Katherine Blunt, *PG&E Had Systemic Problems with Power Line Maintenance, California Probe Finds*, WALL ST. J. (Dec. 3, 2019), https://perma.cc/5TF6-2UKV (describing "numerous serious violations of state rules for maintaining electric lines and specific problems with upkeep of the transmission line that started the fire" that killed eighty-five people); Katherine Blunt & Russell Gold, *PG&E Knew for Years Its Lines Could Spark Wildfires, and Didn't Fix Them*, WALL ST. J. (July 10, 2019), https://perma.cc/2A5E-MBMZ; Douglas MacMillan & Beth Reinhard, *Louisiana Power Outages Renew Questions About Utility Giant's Preparedness for Storms*, WASH. POST (Aug. 31, 2021), https://perma.cc/G62C-NNCQ:

> Entergy, the power provider for 3 million customers in the Gulf region, has over the past decade been fined for deferring maintenance of its aging infrastructure and criticized for moving too slowly to reinforce its grid against severe weather. The company resisted calls to increase investments in renewable energy sources, which climate advocates see as a way to prevent widespread outages.

136 *See* Andrew Graham, *Calif. Bill Would Make PG&E Bury Power Lines Faster*, GOV'T TECH. (Mar. 22, 2022), https://perma.cc/D3R2-WN4X (describing controversy surrounding PG&E's proposal to spend $3.75 million per mile to bury transmission lines).

137 *See, e.g.*, State *ex rel.* Utils. Comm'n v. Stein, 851 S.E.2d 237, 286 (N.C. 2020) (authorizing Duke to include costs of closing coal ash impoundments in the rate base as required under Duke's settlement with EPA for Clean Water Act violations).

138 33 U.S.C. §§ 1251–1387.

139 *See* Michael Biesecker, *Testimony: Health Director Covered Up Cancer-Causing Water in North Carolina*, PBS NEWS HOUR (Aug. 2, 2016), https://perma.cc/NQ4D-V75W.

Rate regulation can also undermine the effectiveness of climate regulations. Consider the revenue impact of a carbon tax. Coal-fired power plants typically emit approximately one ton of carbon dioxide per MWh of electricity. To keep global warming below two degrees Celsius, experts have suggested a global carbon tax of $75 per ton of carbon dioxide. A 500 megawatts (MW) coal-fired power plant can be expected to generate approximately 2,500 MWh of electric energy in a day. A $75 carbon tax that is simply passed through to consumers (as opposed to rate-based and thus entitled to a return) increases customer bills by $4,380,000 a day and $328,000,000 a year. Similarly, a utility may not be inclined to take advantage of clean energy subsidies because doing so reduces its costs, thus reducing the revenue the regulator will authorize it to collect from ratepayers.

Ideally, PUCs would respond to a carbon tax by identifying alternative resource portfolios that would lead to emissions reductions, and they would respond to clean energy subsidies by incorporating more clean energy into their proposed infrastructure investments. But under U.S. law, the default is to allow utilities to raise prices so that they can comply with new regulatory requirements.

And recent experience suggests that regulators are not always willing or able to zealously supervise utilities to make sure they respond to climate policies by making more environmentally friendly and cost-effective investments. When rate-regulated utilities in the United States have experienced carbon pricing or other clean energy regulations, utility tariffs have allowed rate-regulated utilities to rate base the costs of carbon taxes and cap-and-trade regulations. For example, when Virginia joined the Regional Greenhouse Gas Initiative (RGGI), which is a voluntary carbon pricing system in the mid-Atlantic, Dominion Energy passed hundreds of millions of dollars in RGGI-related costs on to its captive ratepayers.[140] Some utilities have not updated their

[140] *See* Order Approving Rate Adjustment Cl., 2021 VA. PUC LEXIS 731, at *16 (Va. St. Corp. Comm'n Aug. 4, 2021) (No. PUR-2020-00169); *cf.* Sarah Vogelsong, *Dominion Asks to Halt Ratepayer Charge for Carbon Market*, VA. MERCURY (May 6, 2022), https://perma.cc/S2YC-ES8M. There are counterexamples. *See, e.g.*, Lauren Shwisberg & Sarah Vorpahl, *What Happens When Utilities Start to Integrate the IRA into Planning?*, ROCKY MOUNTAIN INST. (Jan. 26, 2023), https://perma.cc/S29C-RCKM.

IRPs to incorporate the Inflation Reduction Act's[141] clean energy subsidies.[142]

This does not mean that carbon prices have no beneficial effect in rate-regulated markets. It does, however, mean that the effectiveness of a carbon tax is based on regulatory enforcement and is not directly tied to supply and demand. As a default, a utility will often be able to automatically increase its rates to recover the additional costs imposed by the carbon tax. And, because the utility is charged with developing the integrated resource plan that identifies how it will meet its region's energy needs, the utility is free to propose a plan that passes the costs of the carbon tax on to its customers. Regulators, of course, can review utilities' investments to make sure that utilities are making reasonable decisions. When PUCs determine that different resource portfolios would more cost-effectively meet customer demands, they can order utilities to make different investment decisions. But that process requires a regulatory assessment of the region's resource needs years in advance, and PUCs do not appear to have the capacity or expertise to make these judgments.

Thus, the effectiveness of a carbon tax in rate-regulated markets depends on the willingness of state regulators to order utilities to retire carbon-intensive resources and build cleaner sources of electric capacity. If regulators are risk averse, captured, or lack the ability to fully review utilities' investment decisions, then they may simply defer to the utilities' judgment about how to respond to climate policies.

B. Climate and Reliability Policies in Partially Restructured Markets

Even in restructured markets, the enduring use of rate regulation in nongeneration parts of the supply chain allows utilities to design rules that reduce the effect of regulations that would improve reliability and reduce emissions. Although scholars and policymakers usually draw a categorical distinction between

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141 Pub. L. No. 117-169, 136 Stat. 1818 (2022).

142 *See* ENTERGY LOUISIANA, LLC, 2023 INTEGRATED RESOURCE PLAN 121 (2023). Other utilities simply cap clean energy, rendering them indifferent to IRA subsidies. *See, e.g.*, DUKE ENERGY, 2023 CAROLINAS RESOURCE PLAN, CHAPTER 3: PORTFOLIOS 5–8 (2023); Steven Levitas & Tyler Norris, *Duke Energy Carbon Plan Sells Ratepayers Short*, PV MAG. (Jan. 12, 2023), https://perma.cc/VS8F-RYN9; Testimony of Cypress Creek Renewables Vice President of Development Tyler Norris at 12–18, *In re* Duke Energy Carolinas, No. E-100 Sub 179 (N.C. Utils. Comm'n Sept. 2, 2022).

regions where generation is rate regulated and regions where generators compete in energy auctions, the reality is more complicated. When regulators introduced competition to electric generation, they did not always require full corporate unbundling, which would have forced vertically integrated utilities to sell their generation assets.[143] Instead, many regulators required something called functional unbundling, which required utilities to create separate subsidiaries for their generation assets (with separate management teams) and provide independent, open access to their transmission facilities at regulated rates.[144] Moreover, transmission, distribution, and natural gas pipelines continue to be rate regulated.

A difficulty with functional unbundling is that generators that are owned by LSEs are often able to recover many of their generators' costs in retail rates.[145] In these markets, some generators are independent power producers with no corporate relationship to a rate-regulated affiliate, whereas other generators are subsidiaries of a parent that also owns rate-regulated transmission and retail affiliates. The utilities that own generation, transmission, and retail assets are still vertically integrated.[146] Restructuring in these regions simply indicates that the generators owned by vertically integrated utilities compete with independent power producers. That means that in restructured markets, some generators are, for all intents and purposes, selling electricity to themselves. FERC and grid operators review transmission rates and require all suppliers—including those owned by the transmission operators that move bulk power—to pay to use the transmission lines.

In competitive markets, too, cross-affiliate financing arrangements such as fuel adjustment clauses distort energy market

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143 *See* Order 888, 61 Fed. Reg. at 21,551 (comparing "corporate unbundling" as "includ[ing] selling generation or transmission assets to a non-affiliate (divestiture)" with "functional unbundling," which is "the less aggressive step of establishing separate corporate affiliates to manage a utility's transmission and generation assets").

144 *See id.*:

> We believe that functional unbundling . . . is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

145 For a discussion of how vertical integration in restructured electricity markets allows market power abuses, see Joshua C. Macey & Robert Ward, *MOPR Madness*, 42 ENERGY L.J. 67, 77–79 (2021).

146 *See Electricity Markets 101*, NAT'L GOVERNORS ASS'N, https://perma.cc/9TEU-DK6X.

prices and interact with climate regulations in problematic ways.[147] In theory, all generators, whether independent power producers or affiliates of retail electric providers, should compete based on price. But that does not occur when regulators allow vertically integrated utilities to recover some or all their generators' costs from retail ratepayers.

Fuel adjustment clauses are one example of this. Fuel adjustment clauses are provisions in utility tariffs that allow generators—including generators in restructured markets—to pass their fuel costs on to captive ratepayers.[148] Fuel adjustment clauses are an important source of market incompleteness because they remove utilities' incentives to make investments to keep costs down and make sure they are able deliver power when it is needed. Those costs are passed through to ratepayers, who have limited options to hedge against price volatility, select alternative energy providers, or pay for more reliable service.

Fuel adjustment clauses benefit fossil resources in rate-regulated and non-rate-regulated markets. In rate-regulated markets, fuel adjustment clauses bias resource planning in favor of fuel-intensive resources such as gas and coal. When a utility's rates automatically adjust to cover higher-than-expected fuel costs, the ratemaking process is likely to underestimate the costs of building and operating gas- and coal-fired power plants. That is because the utility can underestimate fossil generators' expected costs and recover excess costs through the automatic fuel adjustment mechanism. Fuel adjustment clauses also reduce rate-regulated utilities' incentives to manage fuel cost risks. A utility that does not properly manage its exposure to fuel price fluctuations is not financially harmed, since it simply passes its fuel costs on to ratepayers.

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[147] Other cross-affiliate financing arrangements amount to a fossil fuel subsidy. For an analysis of cross-affiliate debt guarantees, see generally Aneil Kovvali & Joshua C. Macey, *Hidden Value Transfers in Public Utilities*, 171 U. PA. L. REV. 2129 (2023).

[148] *See In re* Elec. Investigation of the Fuel Adjustment Cl. Regul. 807 KAR 5:056, Purchased Power Costs, & Related Cost Recovery Mechanisms, 2022 WL 16839599, at *1 (Ky. Pub. Serv. Comm'n Nov. 2, 2022):

> [A fuel adjustment clause] is a mechanism for an electric utility to recover its current fuel expense from its customers through an automatic rate adjustment without the necessity for a full regulatory rate proceeding. This rate may increase or decrease from one billing cycle to the next depending on whether the utility's cost of fuel increased or decreased in the same period. The rate provides for a straight pass-through of fuel costs with no allowance for a profit to the utility.

Fuel adjustment clauses are now a pervasive feature of electricity markets and are used in nearly every state.[149] These clauses date back to World War I,[150] and as far back as 1933 a utility proposed a rider that would have allowed it to pass on tax hikes to consumers.[151] They were originally intended to help consumers absorb price shocks that they would have experienced as a result of dramatic fluctuations in coal prices.[152] Regulators authorized fuel adjustment clauses to allow utilities to automatically change rates so that they could cover unavoidable operating expenses.[153]

Once fuel adjustment clauses are included in utility tariffs, they limit regulatory review of utilities' costs, since the fuel costs are automatically passed on to customers. In Kentucky, for instance, utilities proposed fuel adjustment clauses in the 1950s by claiming that these clauses would reduce administrative costs. This argument is somewhat circular: after all, without a fuel adjustment clause, the PUC would have to review utility fuel costs whenever rates changed.[154]

While fuel adjustment clauses may sound like technical provisions of utility tariffs with little practical effect, they have a significant impact on electricity markets. Many large utilities have fuel adjustment clauses that allow them to recover energy costs from ratepayers. In 2021, generators in PJM received more than $30 billion from energy markets.[155] Generators in New England received $6.1 billion from energy markets,[156] and generators in the Midcontinent ISO (MISO)—running from the Midwest to the

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149 *See Fuel Adjustment Clauses and Other Cost Trackers*, *supra* note 13.

150 *See* KEVIN A. KELLY, TIMOTHY M. PRYOR & NAT SIMONS, JR., NAT'L REGUL. RSCH. INST., ELECTRIC FUEL ADJUSTMENT CLAUSE DESIGN 1 (1979).

151 Regulators rejected the proposal. *See* R.S. Trigg, *Escalator Clauses in Public Utility Rate Schedules*, 106 U. PA. L. REV. 964, 965 (1958).

152 *See id.*

153 *See id.*

154 *See In re Elec. Investigation*, 2022 WL 16839599, at *1 ("Fuel adjustment clauses (FAC) have been in tariffs on file with the Commission since the 1950s."); *see also In re* An Investigation of the Fuel Adjustment Cl. Regul. 807 KAR 5:056, 1989 KY. PUC LEXIS 14, at *12 (Ky. Pub. Serv. Comm'n Dec. 18, 1989) (stating that a less generous fuel adjustment clause would be "likely to produce unwanted and undesirable results, including higher administrative costs and inefficiencies such as more frequent rate cases, extensive reviews of base fuel rates at least annually, and the likelihood of expenses for consultants to review the base fuel rates in FAC cases").

155 1 MONITORING ANALYTICS, LLC, 2021 STATE OF THE MARKET REPORT FOR PJM 18 (2022).

156 INTERNAL MKT. MONITOR, ISO NEW ENGLAND, 2021 ANNUAL MARKETS REPORT 7 (2022) [hereinafter INTERNAL MKT. MONITOR, 2021 ANNUAL REPORT].

Gulf of Mexico—received $21 billion.[157] An analysis by the Sierra Club has found that coal-fired generators in MISO lost $3.8 billion from energy market sales between 2015 and 2019.[158] It appears that one reason these units continue to operate is that fuel adjustment clauses allow them to recover that shortfall even though those units would be uneconomic if they were required to cover their costs from energy and capacity market revenues.

Generators with fuel adjustment clauses enjoy a competitive advantage over independent power producers because they can pass their fuel costs on to captive ratepayers.[159] They can therefore submit energy market bids that are lower than their marginal costs, since unlike independent power producers, utilities do not lose money when they submit below-cost bids but instead make up losses in retail rates. The result is that customers pay more for electricity than they would if the energy market cleared the lowest-cost generators. According to one analysis, uneconomic dispatch in MISO, driven partly by fuel adjustment clauses, cost customers $350 million in 2018.[160]

Uneconomic dispatch by rate-regulated firms has perverse effects on competition. Generators with fuel riders need to recover only a percentage of their costs from competitive markets. That

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157 POTOMAC ECON., 2021 STATE OF MARKET REPORT FOR THE MISO ELECTRICITY MARKET 3–7 (2022).

158 *See* JEREMY FISHER, AL ARMENDARIZ, MATTHEW MILLER, BRENDAN PIERPONT, CASEY ROBERTS, JOSH SMITH & GREG WANNIER, PLAYING WITH OTHER PEOPLE'S MONEY: HOW NON-ECONOMIC COAL OPERATIONS DISTORT ENERGY MARKETS 4 (2019).

159 *See* Entergy Ark. LLC, *Commercial and Industrial Electric Energy Price*, ENTERGY, https://perma.cc/MKJ4-GP8K; STATE CORP. COMM'N OF KAN., COST OF GAS RIDER (2016); ENTERGY LA., LLC, FUEL ADJUSTMENT RIDER (2015); DTE ENERGY, UNDERSTANDING YOUR ENERGY BILL (2017); *Rate Riders*, XCEL ENERGY, https://perma.cc/B4Y6-LU7K; Order Approving Rider EEIC Tariff Sheet, *In re* Union Elec. Co. d/b/a Ameren Mo.'s Elec. Serv. Tariffs Adjustment Relating to MEEIA Rider EEIC, 2021 WL 149443 (Mo. Pub. Serv. Comm'n Jan. 13, 2021) (No. ER-2021-0158); *Hearing Before the N.C. H. Energy & Pub. Utils. Comm.*, 153d Gen. Assemb., 1st Sess. 5–7 (Mar. 8, 2017) (statement of Kendal Bowman, Vice President of Regul. and Pub. Affs., Duke Energy); Supplement No. 15 at 24, Pa. Pub. Util. Comm'n v. West Penn Power Co., 2017 WL 395349 (Pa. Pub. Util. Comm'n Jan. 19, 2017) (No. R-2016-2537359); Rider 39: Adjustment for Fuel, Variable Environmental, Avoided Capacity Costs and Distributed Energy Resource Program Costs at 1, *In re* Ann. Rev. of Base Rates for Fuel Costs of Duke Energy Progress, 2023 WL 4997840 (S.C. Pub. Serv. Comm'n July 31, 2023) (No. 2023-1-E); ENTERGY TEXAS, INC., GENERATION COST RECOVERY RIDER, SHEET NO. 136 (2022); Petition of Virginia Elec. & Power Co., 2022 WL 1026844 , at *2 (Va. State Corp. Comm'n Apr. 1, 2022) (No. PUR-2021-00281).

160 JOE DANIEL, SANDRA SATTLER, ASHTIN MASSIE & MIKE JACOBS, UNION OF CONCERNED SCIENTISTS, USED, BUT HOW USEFUL? HOW ELECTRIC UTILITIES EXPLOIT LOOPHOLES, FORCING CUSTOMERS TO BAIL OUT UNECONOMIC COAL-FIRED POWER PLANTS 5 (2020).

allows those resources to underbid their competitors and be dispatched more frequently than they would be if they had to sell electricity competitively. Moreover, lower energy prices do not translate into lower bills for consumers, since fuel riders allow generators to recover their costs from captive ratepayers. Thus, customers are forced to purchase more expensive electricity than they would if vertically integrated firms had to compete on a level playing field.

Fuel adjustment clauses also have negative effects on reliability. Firms that are allowed to recover their fuel costs from their ratepayers have reduced incentives to hedge against fuel price volatility. Generators with fuel adjustment clauses are not harmed when fuel prices go up, since fuel adjustment clauses force ratepayers to take on the risk of fuel price volatility. In the past few years, this has cost customers billions of dollars. For example, while Texas received most of the press in the immediate aftermath of the February 2021 blackouts, other states that experienced power outages charged customers—many of whom lost power—billions of dollars for utilities' fuel costs during winter storms. An Oklahoma utility, Oklahoma Natural Gas, was unable to purchase enough gas to meet the state's energy demands in February 2021. Thousands of people lost power and heat.[161] The price of gas skyrocketed to nearly six hundred times its ordinary price.[162] Yet the company's fuel adjustment clause allowed it to charge customers $1.4 billion to cover its fuel costs during that event.[163] Oklahoma ratepayers were thus required to bear the costs of the company's failure to hedge against gas prices.

Fuel adjustment clauses can also counteract priced-based climate policies. Some economists have argued that carbon taxes should be imposed on extraction and production to reduce administrative costs, or, when accounting for leakage, that the taxes

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161 *See* Jack Money, *Winter Storm Leaves Thousands of Oklahomans Without Power in Freezing Temperatures*, OKLAHOMAN (Feb. 2, 2022), https://perma.cc/E969-JGQV.

162 *See* Paul Monies, *Oklahomans Face $1.4 Billion Bill After Historic Arctic Blast*, J. REC. (Jan. 20, 2022), https://perma.cc/S3LD-BN54.

163 *See id.*

should be levied on both production and consumption.[164] Others have argued that a carbon tax should be levied on emissions.[165]

Without taking a position on this debate, it is worth noting that the design of a carbon tax should be attentive to sources of incompleteness and to utilities' ability to pass environmental costs on to captive customers. For example, a tax on consumption will be less effective in rate-regulated markets where customers cannot switch suppliers and when the prices customers pay does not reflect the real-time costs of generating electric energy. Similarly, the arguments for levying a carbon tax against producers make more sense when the costs of the tax are borne by fossil fuel companies. But that is not the case when fuel adjustment clauses allow firms to pass costs on to their captive ratepayers. If a carbon tax applies to production, then a generator with a fuel adjustment clause will not increase its bid in response to the carbon tax. Unlike the independent power producer, the generator with a fuel adjustment clause does not have to increase its bid to make sure that it can recover its costs from the energy market.

This has a few implications for the optimal design of price-based climate policies. The first is that carbon taxes can increase the profits some carbon-intensive resources earn from energy markets. When a carbon tax increases the market clearing price, a generator that does not respond to the carbon price will clear more often and therefore earn a higher profit. By driving the energy price up, the carbon tax increases the inframarginal rents vertically integrated utilities earn from energy markets.

The second implication is that the effectiveness of a carbon price may change based on technical energy market rules that allow firms to socialize the costs of climate policies. Economists have persuasively argued that a carbon tax will be most effective if it is imposed on production. There are fewer producers, so the administrative costs of levying a tax against producers is

164 *See* David Weisbach, Samuel S. Kortum, Michael Wang & Yujia Yao, *Trade, Leakage, and the Design of a Carbon Tax* 28–31 (Nat'l Bureau of Econ. Rsch., Working Paper No. 30244, 2022) [hereinafter Weisbach et al., *Trade, Leakage, and the Design of a Carbon Tax*]. *But see* Samuel Kortum & David Weisbach, *The Design of Border Adjustments for Carbon Prices*, 70 NAT'L TAX J. 421, 440 (2017); Samuel Kortum & David A. Weisbach, *Optimal Unilateral Carbon Policy* 2 (Cowles Found. Discussion Paper No. 2311, 2021).

165 Joseph E. Aldy & Robert N. Stavins, *Using the Market to Address Climate Change: Insights from Theory and Experience* 5–7 (Nat'l Bureau of Econ. Rsch., Working Paper No. 17488, 2011).

relatively low.[166] Moreover, when academics have worried about leakage—the possibility that a carbon tax will cause carbon intensive resources to move offshore—they have instead argued that the tax should be imposed both on production and demand.[167]

These findings appear to be correct in the context of a market in which parties are price responsive, but not when market rules such as fuel adjustment clauses allow market participants to pass the costs of climate policy on to captive ratepayers. Market liberalization can therefore make it easier to administer optimal climate policies. Where liberalization is not possible, policymakers should account for market imperfections that counteract the impacts of those impacts when designing climate policies.

The third implication is that climate policy can, perversely, entrench the market power of carbon-intensive firms. When a carbon tax increases the market clearing price from $30 to $40 per MWh, independent power producers that emit carbon dioxide experience cost increases, so they do not benefit from higher energy market prices. However, a generator that has a fuel adjustment clause will, as discussed, earn additional profits. Energy markets are already highly concentrated, and regulators frequently express concern that vertically integrated firms are abusing their market power. To the extent that carbon taxes increase the unearned advantage that vertically integrated firms have compared to independent power producers, they can lead to increased market concentration that may facilitate future market power abuses.

From a climate standpoint, this is problematic because it can increase the profits that dirtier units earn and push less carbon-intensive resources out of the market. For example, if a vertically integrated utility has a fuel rider that allows it to pass the costs of coal on to its ratepayers, a carbon price may push gas-fired generators out of the market while increasing the inframarginal rents that certain coal-fired units receive. From the perspective of competition, this is problematic because it amounts to a subsidy that could push firms that operate cheaper or cleaner generating

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166 *See* Gilbert E. Metcalf & David Weisbach, *The Design of a Carbon Tax*, 33 HARV. ENVTL. L. REV. 499, 501 (2009) ("[W]e show that collecting the tax upstream would make it possible to accurately and cheaply cover 80% of U.S. emissions by collecting the tax at fewer than 3000 points, and that it would be possible to cover close to 90% of U.S. emissions at a modest additional cost.").

167 *See* Weisbach et al., *Trade, Leakage, and the Design of a Carbon Tax*, *supra* note 164, at 2–3.

units out of the market simply because those firms cannot externalize their social costs onto ratepayers.

It is difficult to discern any economic or policy justification for fuel adjustment clauses. Utilities proposed them in integrated resource plans, sometimes more than a century ago. Often, these clauses adjust automatically and in the absence of regulatory oversight. Again, the fact that utilities have legal authority to write market rules and make investment decisions allows them to create a market in which they are indifferent to the costs of climate and reliability regulations.

Fuel adjustment clauses are only one way in which rate regulation interacts with market incompleteness to counteract climate and reliability policies. Regulators' failure to order full corporate unbundling also facilitates market power abuses by utilities that own generation, transmission, and distribution franchises. Because those sources of incompleteness implicate both rate regulation and market power issues, I discuss them in the market power section in Part III.

III. PRO-INCUMBENT MARKET RULES

Additional sources of incompleteness arise from the various regulations that have developed in restructured markets. Many market rules that favor incumbent firms and disfavor clean energy resources aim to ensure that sufficient supply enters and remains in the market. While some of these regulatory interventions respond to genuine concerns about reliability and generator market power, they frequently do so in a way that favors firms and types of resources that control RTO governance. As discussed in Part III.B, many of these rules come out of decision-making processes in which incumbent utilities hold outsized influence.

A. Offer Caps and Resource Adequacy Markets

A recurring feature of reliability regulations is that they reduce the efficacy of climate policies. Many reliability policies are justified by concerns that, left unregulated, energy markets would be vulnerable to market power abuses.[168] To mitigate market power abuses, every RTO in the United States has introduced offer caps. Offer caps are a source of market incompleteness

[168] For an influential assessment of market power in electricity markets, see generally Severin Borenstein, James Bushnell & Christopher R. Knittel, *Market Power in Electricity Markets: Beyond Concentration Measures*, 20 ENERGY J. 65 (1999).

because they make it impossible for customers to pay above a certain price for electricity during capacity shortfalls. The grid operator creates a demand curve. The reliability challenges that occur as a result of offer caps have been the subject of much scholarly writing, so I focus on the climate implications.[169]

The first challenge is that offer caps can themselves reduce the effectiveness of climate policies. Carbon taxes should lead to emissions reductions in two ways. First, they force resources that emit carbon dioxide to bear the social costs of their emissions. Second, they drive the energy market price up, so that resources that do not emit greenhouse gases receive additional revenue. For example, when a carbon tax causes a gas-fired generator to increase its bid from $30 to $40 per MWh, the carbon tax both reduces the frequency with which the generator is dispatched and increases the revenue less carbon-intensive resources receive from the energy market. If the carbon tax increases the clearing price from $30 to $40 per MWh, it increases the revenue that solar and wind receive by a third. Both have zero marginal costs and therefore would have cleared the market and earned a $30 per MWh profit before the carbon tax was imposed. Because the carbon tax causes the energy market price to increase from $30 to $40, it therefore increases the revenue wind and solar earn. And, because the tax does not cause their costs to go up, their profits increase from $30 to $40 per MWh. Moreover, by increasing the revenue available to low-carbon resources, the carbon tax increases market entry from those resources, since additional energy market revenue makes it easier for them to recover their fixed costs.

Offer caps could undercut the revenue-enhancing effect of a carbon tax. If a carbon tax is applied in a market in which prices are capped at $2,000 per MWh, then $2,000 per MWh creates a revenue ceiling for clean resources. In one respect, that could support decarbonization, because it could push carbon intensive resources out of the market. If a carbon tax pushes a coal-fired generator's marginal costs to $2,100 per MWh, then the offer cap prevents that unit from being dispatched. However, in preventing the carbon-intensive unit from being dispatched, the offer cap also

169 *See generally* Spence & Prentice, *supra* note 54; Paul Joskow & Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000* 2 (Nat'l Bureau Econ. Rsch. Working Paper No. 8157, 2001) ("We show that during high demand periods in California it is profitable for suppliers holding a portfolio of generating units with diverse marginal supply costs to withdraw capacity from the market even under otherwise competitive conditions.").

reduces the revenue available for clean resources and therefore reduces the incentive for less carbon-intensive resources to enter the market. These two effects offset each other, and the aggregate effect on climate policy is therefore difficult to assess qualitatively and likely depends on idiosyncratic features of each market.[170]

But the real problem is that offer caps have induced grid operators to develop alternative sources of revenue that disfavor renewables in the market and otherwise undercut the effect of state and federal climate policies. One example is the use of uplift payments to compensate coal- and gas-fired power plants that are costly to turn on and off.[171] It is hard to identify an economic justification for uplift payments. The central principle of restructured electricity markets is that low-cost units should be dispatched before more expensive units so that customers receive electricity from the cheapest available units. When grid operators offer payments that allow generators to recover the costs of turning on outside of the energy market, they distort the supply curve by allowing more expensive generators to be dispatched before cheaper ones.

In many markets, uplift payments make up a significant percentage of generator revenue. One FERC proceeding found that RTOs paid more than $5.5 billion in uplift payments between 2009 and 2013.[172] And that number appears to be increasing. The generators in PJM that received the most revenue from uplift payments between 2009 and 2013[173] have more than tripled the amount of revenue they receive from uplift payments in the past six years.[174] While gas- and coal-fired power plants that receive uplift payments are still subject to a potential carbon tax, the use of uplift payments takes money out of the energy market and therefore reduces the extent to which a carbon tax increases the energy market price. That reduces the revenue that comes from the energy market, which reduces compensation for low-carbon

170 Note, moreover, that a carbon tax that increases the energy market price exacerbates the missing money problem. By driving generators' costs up, the carbon tax means that offer caps have to be higher in order for generators to cover their costs. But if grid operators raise offer caps, then they increase the economic benefits of withholding supply, which could increase firms' incentives to abuse their market power. And if grid operators do not raise the offer cap, they exacerbate the missing money problem.

171 *See Understanding Uplift and Out-of-Market Payments*, PJM LEARNING CTR., https://perma.cc/7WUF-SUML.

172 *See* FERC, STAFF ANALYSIS OF UPLIFT IN RTO AND ISO MARKETS 5 (2014).

173 *See id.*

174 *See* 4 MONITORING ANALYTICS, LLC, 2021 STATE OF THE MARKET REPORT FOR PJM 251–52 (2022).

resources.[175] Similarly, to the extent that clean energy subsidies reduce the energy market price and thus drive down the revenue available to carbon-intensive resources, uplift payments provide an alternative revenue source that counteracts—at least to some extent—subsidies' price suppressive effect.

But perhaps the more important respect in which market power concerns have led to regulatory responses that counteract clean energy policies is through the development of resource adequacy markets that disfavor low-carbon resources. By definition, a capacity market takes money out of the energy market. A resource that can recover some or all its fixed costs from capacity or other resource adequacy markets does not need to receive as much revenue from the energy market. Thus, as capacity market revenues increase, the percentage of total generator revenue that comes from energy markets decreases. In the past fifteen years, the percentage of generator revenue that comes from capacity markets in East Coast RTOs has increased from 3% to well over 30%.[176]

That might only be a slight problem if capacity markets were well designed, since clean energy resources that provide reliability benefits would be compensated for doing so.[177] Unfortunately,

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175 In fact, carbon-pricing instruments exacerbate the distortions caused by uplift payments. If those power plants had to recover all their costs from energy markets, then those resources would submit higher energy market bids, which would increase the revenue energy markets provide to low-carbon resources. A carbon price that causes carbon-intensive resources to operate less frequently also causes those resources to turn on and off more frequently. That, in turn, results in those firms receiving more revenue from uplift payments. When a higher percentage of generators' fixed costs do not come from the energy market, the result is to push the energy market price down, thus lowering the revenues low-carbon resources would receive if dirty units were not able to cover a large percentage of their revenues from uplift payments. Uplift payments thus partly counteract carbon pricing by providing a larger and larger percentage of revenue to carbon-intensive resources when the carbon price goes up.

176 Capacity markets now account for nearly a quarter of total revenues in some markets. *See* 2 MONITORING ANALYTICS, LLC, 2018 STATE OF THE MARKET REPORT FOR PJM: DETAILED ANALYSIS 16 (2019), https://perma.cc/W67Y-C344 (stating that capacity markets accounted for $10.3 billion of generator revenues in 2018, while total generator revenues amounted to $41.4 billion (subtracting transmission payments and administrative fees from total price), such that the capacity share is 24.9%). As of 2018, that number was nearly thirty percent in ISO-NE. *See* ISO NEW. ENG., 2018 ANNUAL MARKETS REPORT 4–5 (2019), https://perma.cc/K2AJ-XTXT. *See also Energy Price Formation and Valuing Flexibility*, PJM (June 15, 2017), https://perma.cc/RD8K-8JBS (demonstrating how capacity markets used to account for basically nothing in PJM); 2022 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS, POTOMAC ECON. 19 (2023) (showing a few over thirty, especially in 2020).

177 Even well-designed capacity markets are ill-equipped to support high volumes of renewable resources. As Professor Jacob Mays has shown, capacity markets favor fossil generators over carbon-free ones. *See* Mays, Morton & O'Neill, *supra* note 12, at 953 ("The

capacity markets contain numerous rules that disfavor renewables.[178] For example, as I have written about elsewhere, most capacity markets operate on a three-year lag and thus determine market entry and exit on the basis of outdated cost assumptions.[179] In the past decade, the costs of solar and storage have declined significantly.[180] Thus, capacity markets clear fewer clean energy resources than they would if they responded to current market conditions. In addition, capacity market accreditation overcompensates fossil resources that fail to perform during extreme weather events and thus have overcompensated gas resources.[181] Capacity markets also have historically used performance requirements that contain outdated and often incorrect assumptions to determine which resources can enter and exit the market. One example is requiring eight-hour performance duration requirement for battery storage when there is considerable evidence that four-hour duration would provide significant capacity benefits.[182]

Perhaps the most controversial example of how resource adequacy markets are sources of market incompleteness is RTO rules that exclude renewables altogether from capacity markets. Three RTOs—PJM in the mid-Atlantic, ISO-NE in New England, and NYISO in New York—have all developed some version of a "minimum offer price rule," known as a MOPR (pronounced MOPE-er). These rules set a minimum bid amount for certain resources—often resources that receive state subsidies.[183] The most aggressive MOPRs were scaled back after significant controversy.

majority of energy in low-carbon systems is likely to be provided by some combination of hydroelectric, nuclear, wind and solar resources, all of which are characterized by high capital costs and low operating costs. Accordingly, capacity markets as currently structured may work against efforts to decarbonize."). *See generally* Mays, *Missing Incentives*, *supra* note 12.

178 *See* Macey & Salovaara, *Rate Regulation Redux*, *supra* note 12, at 1236–54.

179 Over the past decade, the cost of solar and battery storage has come down more than 80%. *See Documenting a Decade of Cost Declines for PV Systems*, NAT'L RENEWABLES ENERGY LAB (Feb. 10, 2021), https://perma.cc/KJ2H-RHHY.

180 *See* Max Roser, *Why Did Renewables Become So Cheap So Fast?*, OUR WORLD IN DATA (Dec. 1, 2020), https://perma.cc/63ZA-W9PX; Veronika Henze, *Battery Pack Prices Cited Below $100/kWh for the First Time in 2020, While Market Average Sits at $137/kWh*, BLOOMBERGNEF (Dec. 16, 2020), https://perma.cc/NXN2-A6WQ.

181 *See* Mays & Macey, Accreditation, Performance, and Credit Risk, *supra* note 12, at 16–17; *see also* Mays, Morton & O'Neill, *supra* note 12, at 949.

182 *See* Macey & Salovaara, *Rate Regulation Redux*, *supra* note 12, at 1238.

183 MOPRs have different names in different regions. NYISO uses the phrase "buyer-side market power mitigation rule"; ISO-NE uses the phrase "out-of-market payment." *See* Macey & Ward, *supra* note 145, at 77, 98.

If enacted, however, they could have excluded clean energy resources from markets that accounted for more than 30% of generator revenues in certain years in PJM, ISO-NE, and NYISO.[184]

The interventions described above are certainly not comprehensive. The point is that resource adequacy markets limit—or, in some cases, altogether exclude—resources that reduce emissions and improve reliability. When a grid operator over-accredits gas resources, gas-fired generators earn excessive revenue, causing more gas to enter the market than would occur if grid operators properly valued capacity. A poorly designed capacity market also creates additional incentives for grid operators to find ways to induce additional units to enter the market to reduce the likelihood of blackouts. All these interventions take money out of energy markets and thus reduce the revenues available to generators—including renewables—that are able to sell energy when it is needed.

B. The Role of Filing Rights in RTO History

A strange feature of the United States' electric grid is, when regulators sought to encourage competitive and nondiscriminatory electricity markets, they did so by encouraging incumbent utilities to create and govern the organizations that would administer and regulate electricity markets. This dynamic occurred in all RTOs, though this Section focuses on ISO-NE and PJM.

In New England, filing rights are split between ISO-NE, which is the region's RTO, and NEPOOL, which previously operated a power pool among New England utilities but now serves as a stakeholder-advisor group for issues related to wholesale market design and transmission owners.[185] In NEPOOL, three voting sectors represent generation, transmission, and distribution companies that own or operate assets in the region.[186] NEPOOL has served as a voluntary organization of transmission and generation owners since 1971. When NEPOOL was created, the parties that formed the power pool agreed that firms that were responsible for serving a large percentage of the region's customers or providing a large percentage of the region's power should accordingly have additional votes and be able to veto certain

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184 *See infra* note 177.

185 *About NEPOOL*, *supra* note 86.

186 *See* NEPOOL, SECOND RESTATED AGREEMENT, *supra* note 90, at 19.

proposals.[187] Following FERC Order No. 888, NEPOOL contracted with an independent entity, ISO-NE, to perform the functions of an ISO. ISO-NE began operation in 1997. Based on utilities' Order No. 888 submission, NEPOOL retained the right to sponsor section 205 proposals.[188]

When New England utilities initially proposed to form an ISO, they proposed that ISO-NE would be run by a board consisting of ten nonstakeholder directors who serve three-year staggered terms.[189] The Board would have exclusive decision-making authority, including authority over tariffs, market rules, and the operating and capital budgets. ISO-NE relied heavily on a stakeholder advisory process that would be comprised of five sectors representing generators, TOs, suppliers, publicly owned entities, and end users.[190] The board would be selected by a nominating committee composed of up to six incumbent members of the board, up to five market-participant representatives (not including more than one representative from any sector), and one representative from the New England Conference of Public Utilities Commission.[191] FERC largely accepted ISO-NE's proposed governance structure but insisted that alternative energy providers should be adequately represented within stakeholder advisory processes.[192]

In PJM, too, incumbent utilities initially proposed a governance arrangement that was highly favorable to them. At first, FERC did not accept utilities' proposal to form PJM, largely in response to concerns about how the ISO would be governed. FERC pointed out that "[n]umerous intervenors argue that the proposed market structure would result in perpetuating the

187 *See, e.g.*, New England Power Pool Agreement § 5.1 (on file with author) ("There shall be a Management Committee which shall be constituted as follows: each Participant shall have the right to appoint and be represented by one member of the Management Committee; and each Participant whose Annual Peak equals or exceeds twenty percent of the sum of the Annual Peaks of all Participants shall have the right, so long as such condition continues, to appoint and be represented by one additional member for each full ten percent that its Annual Peak exceeds ten percent of said sum."); *id.* § 5.3 ("Each member of the Management Committee shall have the right to cast a number of votes equal to the Annual Peak of the Participant which he represents."); *id.* § 5.4 ("upon an affirmative vote of members having at least seventy-five percent of the total number of votes to which all members are entitled; provided, however, that the negative votes of any two or more members having at least fifteen percent of such total number of votes shall defeat any proposed action.").

188 ISO New Eng. Inc. v. New Eng. Power Pool, 106 F.E.R.C. ¶ 61,280, at p. 62,022 (2004).

189 *See id.* at p. 62,027.

190 *See id.*

191 *See id.*

192 *See id.* at p. 62,029.

existing PJM members' market power."[193] One problem was that the transmission committee would have authority to "nam[e] two ISO board members."[194] Another problem was that "[t]he number of votes of each member of the [committee in charge of market operations] is based on its volume of electric energy transactions in the PJM control area."[195] Partly in response to these governance concerns, FERC rejected the incumbent utilities' first proposal to certify PJM as an ISO.

PJM's current five-sector governance arrangement, described below, came about after a considerable amount of compromise between FERC and mid-Atlantic utilities. Despite the concerns I have expressed about PJM's governance structure, the framework that emerged in response to Order No. 888 reflected an enormous degree of collaboration. When FERC certified PJM in 1997, it approved a Transmission Owners Agreement, an Open Access Transmission Tariff, a Reliability Assurance Agreement, and an Operating Agreement.[196] FERC accepted PJM's five-sector governance structure after multiple rounds of back-and-forth in which the Commission rejected proposals that would have given utilities an even tighter grip over PJM governance.

Still, when FERC certified PJM in 1997, it conceded to utilities a significant amount of control over the RTO.[197] In addition to direct means of control such as voting, the Commission also authorized carveouts, discussed in Part IV, that have allowed them to protect their own interests; FERC did so only after rejecting previous proposals largely because the Commission was not satisfied that PJM would be independent of incumbent interests.[198]

Utilities have used that control to prevent environmental stakeholders from participating in PJM governance. In 2022, the Citizens Utility Board, which is a group that advocates on behalf of energy consumers, proposed amending the PJM Operating Agreement to add a seat to the PJM Board.[199] The proposal would

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193 PJM Guidance Order, Atl. City Elec. Co., 77 F.E.R.C. ¶ 61,148, at p. 61,564 (1996).

194 *Id.* at p. 61,561.

195 *Id.*

196 Pennsylvania-New Jersey-Maryland Interconnection, 81 F.E.R.C. ¶ 61,257, at p. 62,235 (1997).

197 *See* PJM, *Governance*, PJM LEARNING CENTER, https://perma.cc/HP8U-8CST ("The Members Committee reviews and decides upon all major changes and initiatives . . . [it] provides advice and recommendations to PJM on all matters.").

198 In these filings, the utilities proposed forming an ISO.

199 *See* DAKE KOLATA & ALBERT POLLARD, PJM ENVIRONMENTAL GOVERNANCE PROPOSAL (2022).

have required that the additional board member be an expert on climate change and decarbonization.[200] When PJM rejected the proposal, it passed a motion suspending the rules that ordinarily require PJM to provide a voting report.[201] As a result, PJM's Board continues to provide little representation to environmental interests, and, because the process was opaque, it is impossible to know which members and which utilities opposed this motion.

Another recent example illustrates the extent to which utilities use their filing rights to impede climate policies to protect their financial interests. In February 2024, PJM transmission owners proposed to unilaterally amend the Consolidated Transmission Owners Agreement (CTOA) to increase their control over transmission planning.[202] The CTOA is one of PJM's governing documents. It is an agreement between PJM and transmission companies that allocates rights and obligations between transmission owners and PJM.[203] Among other things, it clarifies that PJM will conduct regional transmission planning while transmission owners will retain filing rights to cover the costs of maintaining and building their own transmission facilities.[204] A

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[200] *See id.*

[201] *See* PJM, MINUTES OF THE 251ST MEETING OF THE PJM MEMBERS COMMITTEE ON OCTOBER 26, 2022, at 2 (2022).

[202] *See* Memorandum from Am. Elec. Power Serv. Corp., AES Ohio, Exelon Corp. and PPL Elec. Utils. Corp. to Chair of the Transmission Owners Agreement Admin. Comm. § 4.1.4.(b)(ii) (Feb. 6, 2024) (on file with author):

> Where Transmission Facilities planned by a Party may overlap with Transmission Facilities proposed to be included in the Regional Transmission Expansion Plan such that the Transmission Facilities proposed to be included in the Regional Transmission Expansion Plan would more efficiently and cost effectively address the need for which the Party's Transmission Facilities are planned, PJM shall consult with the Party to determine if the need for which the Party's Transmission Facilities are planned will be addressed. If the Party determines that such need will not be addressed and that it must continue to plan the Party's Transmission Facilities, it shall document to PJM and the relevant PJM transmission planning committee the rationale supporting its determination.

[203] *See id.* ¶ 1:

> "This CONSOLIDATED TRANSMISSION OWNERS AGREEMENT ("Agreement") dated as of the 15th day of December 2005, is made by and among the Transmission Owners (hereinafter referred to collectively as "Parties" and individually as a "Party"). In addition, this Agreement is made by and between the Parties and PJM Interconnection, L.L.C. (hereinafter referred to as "PJM") solely for the purpose of establishing the respective rights and commitments of the Parties and PJM identified herein.").

[204] *Id.* § 7.1.1 ("Each Party shall have the exclusive right to file unilaterally at any time pursuant to Section 205 of the Federal Power Act to establish or change the

concerning part of the recent proposed amendments is that they would ensure that when there is conflict between PJM's regional plan and a TO's local planning, the local plan wins.[205] TOs could undermine regional transmission planning simply by announcing that they plan to meet the need themselves.

This may seem like a technical and arcane issue (and it appears to be outside of utilities' legal authority[206]), yet the stakes are high. As the next Part explains, deep decarbonization requires rapidly expanding the transmission system, and utilities often have little incentive to build high-voltage interstate transmission lines.[207] If utilities use local planning to reduce the need to build regional and interregional lines, it will be much more difficult for the United States to build a grid capable of supporting rapid decarbonization. Equally important, if incumbent transmission owners can reclaim their filing rights at any point, it is unclear how PJM could ever implement reforms over TO opposition.

Utilities also possess substantial influence over grid governance in other RTOs and in other important grid actors such as reliability entities. All these governance arrangements were proposed by utilities, and the governance structures that went into effect often came after multiple filings in which FERC ordered utilities to revise the RTOs governance proposals. When FERC rejected utilities' proposals, it typically did so because it was not satisfied that the proposed governance arrangements adequately represented stakeholders. Thus, although RTO governance could have been much worse, RTOs currently look the way that they do because the utilities that owned most power sector infrastructure in the 1990s proposed governance regimes that aligned with their own interests. Once again, FERC was constrained by the fact that it had to respond to the filings submitted by investor-owned utilities.

transmission revenue requirement for services provided under the PJM Tariff with respect to its Transmission Facilities.").

205 *See id.* § 4.1.4(b)(ii).

206 The CTOA is a contract between the TOs and PJM. As a result, while TOs have authority to unilaterally propose changes over some filing rights—the rights they retained—they cannot unilaterally reclaim filing rights they have already given up. Doing so requires either an agreement between TOs and PJM, or joint filings by the TOs and PJM. Moreover, the proposed changes are unjust and unreasonable. The most obvious legal deficiencies are that they would undermine regional planning and make it impossible for PJM to satisfy Order No. 2000's independence requirement.

207 *See infra* Part IV.

While it is impossible to prove that RTOs' misaligned incentives are the reason that RTOs continue to adopt market rules that favor incumbents and impede the clean energy transition, these rules are at least consistent with the incentives of the firms that have outsized influence in the governance of the RTOs that develop these rules. As discussed in Part I.B, utilities that owned most generation and transmission infrastructure used their filing rights to ensure that they enjoy outsized representation on RTO boards and committees. And the specific rules discussed in this section were promulgated by subcommittees that are controlled by utilities that benefitted financially from these rules.

IV. TRANSMISSION

Transmission policy in the United States shows how utilities can use their residual filing rights to take advantage of jurisdictional gaps to protect their own financial interests, often to the detriment of grid reliability and clean energy policies. Even when FERC has pushed for competitive regional and interregional transmission planning, utilities have managed to use their filing rights to undermine transmission reforms.

A. Challenges to Modern Transmission Planning

The best wind and solar resources are typically located far from demand centers. To bring cheap renewables to market, utility-scale wind and solar must be constructed where they will be most productive, and the electricity they generate must be transported across large distances so that it can reach consumers.[208]

Transmission is also important for system reliability. Transmission allows regions to import electricity from other areas that have surplus capacity. During Winter Storm Uri, much of the

[208] *See* Matthew L. Wald, *Wind Energy Bumps into Power Grid's Limits*, N.Y. TIMES (Aug. 26, 2008), https://www.nytimes.com/2008/08/27/business/27grid.html:

> The dirty secret of clean energy is that while generating it is getting easier, moving it to market is not.
>
> . . .
>
> Achieving [deep decarbonization] would require moving large amounts of power over long distances, from the windy, lightly populated plains in the middle of the country to the coasts where many people live.

See also ERIC LARSON ET AL., ANDLINGER CTR. FOR THE ENERGY & THE ENV'T, PRINCETON UNIV., NET-ZERO AMERICA: POTENTIAL PATHWAYS, INFRASTRUCTURE, AND IMPACTS 24–29 (Final Report Summary 2021) (modeling transmission developments needed to support deep decarbonization and finding that the United States needs to increase transmission capacity by between two and five times).

Midwest was able to avoid cascading outages because LSEs imported electricity from areas that were not being hit by the storm. Regulators have estimated that the ability to import power from the East Coast allowed northern parts of the Midwest to avoid hundreds of thousands of outages and billions of dollars in economic losses.[209] Areas further to the South, including Texas, Missouri, Oklahoma, and Louisiana, fared much worse. According to reliability regulators, these regions would have been able to keep the lights on if they had built transmission that allowed them to import electricity from other areas.[210]

Transmission can also reduce market concentration and mitigate market power abuses. Transmission constraints prevent electric generators from selling electricity to capacity-constrained regions. Additional transmission, especially large regional and interregional projects, allows resources to sell to load centers in distant geographic areas. A generator that would have been able to raise prices by withholding electric energy may find itself unable to do so when the region can draw upon a greater number of electric generators to meet demand.[211]

But the legal rules governing transmission development make it difficult to build a grid capable of supporting the country's climate and reliability needs. The first challenge for transmission development, which has been the subject of much legal commentary, is that the country's siting laws favor incumbent utilities and create barriers to the development of large-scale transmission projects.[212] While FERC has authority to regulate

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[209] *See* FERC & N. AM. ELEC. RELIABILITY CORP., FEBRUARY 2021 COLD WEATHER GRID OPERATIONS: PRELIMINARY FINDINGS AND RECOMMENDATIONS 10 (2021) ("MISO's and SPP's ability to transfer power through their many transmission ties with adjacent Balancing Authorities in the Eastern Interconnection helped to alleviate their generation shortfalls.").

[210] *See id.* (noting that Texas "did not have the ability to import many thousands of MW from the Eastern Interconnection").

[211] For a discussion of the competitive benefits of transmission, see Severin Borenstein, James Bushnell & Steven Stoft, *The Competitive Effects of Transmission Capacity in a Deregulated Electricity Industry*, 31 RAND J. ECON. 294, 294–96 (2000).

[212] *See, e.g.*, Alexandra B. Klass, *The Electric Grid at a Crossroads: A Regional Approach to Siting Transmission Lines*, 48 U.C. DAVIS L. REV. 1895, 1948–51 (2015) [hereinafter Klass, *Crossroads*]; U.S. DEP'T OF ENERGY, SUMMARY OF FINDINGS: IN RE APPLICATION OF CLEAN ENERGY PARTNERS LLC PURSUANT TO SECTION 1222 OF THE ENERGY POLICY ACT OF 2005, at 5 (2016) (describing state impediments to merchant transmission); Alexandra B. Klass, *Takings and Transmission*, 91 N.C. L. REV. 1079, 1144–47 (2013) (describing state-based barriers to interstate transmission); Alexandra B. Klass & Jim Rossi, *Reconstituting the Federalism Battle in Energy Transportation*, 41 HARV. ENVTL. L. REV. 423, 428 (2017) [hereinafter Klass & Rossi, *Federalism Battle*] (arguing for

transmission planning and cost allocation, states have authority over transmission siting. State siting laws contain a number of veto points that allow utilities and other stakeholders to block new lines,[213] and transmission lines capable of transmitting utility-scale solar and wind to large electricity markets are frequently blocked due to siting issues.[214] Some states only allow incumbent transmission owners to build new lines and exercise eminent domain authority.[215]

A second challenge is that the federal planning process gives developers an incentive *not* to build regional and interregional lines needed to import clean electricity and make the bulk power system more resilient.[216] There are two reasons federal planning

a greater federal role in transmission line siting); Ashley C. Brown & Jim Rossi, *Siting Transmission Lines in a Changed Milieu: Evolving Notions of the "Public Interest" in Balancing State and Regional Considerations*, 81 U. COLO. L. REV. 705, 719–27 (2010) [hereinafter Brown & Rossi, *Siting Transmission Lines*]; Avi Zevin, Sam Walsh, Justin Gundlach & Isabel Carey, *Building a New Grid Without New Legislation: A Path to Revitalizing Federal Transmission Authorities*, 48 ECOLOGY L. Q. 169, 182–89 (2021) [hereinafter Zevin et al., *Building a New Grid*].

213 *See* JOSEPH H. ETO, LAWRENCE BERKELEY NAT'L LAB'Y, BUILDING ELECTRIC TRANSMISSION LINES: A REVIEW OF RECENT TRANSMISSION PROJECTS 19–21 (2016) (describing failed transmission projects); *see also* Kristen van de Biezenbos, *The Case Against Regional Transmission Monopolies*, 101 WASH. U. L. REV. 69, 92–95 (2023); Alexandra B. Klass, *Expanding the U.S. Electric Transmission and Distribution Grid to Meet Deep Decarbonization Goals*, 47 ENVTL. L. REP. 10749, 10756–58 (2017); Alexandra B. Klass & Jim Rossi, *Revitalizing Dormant Commerce Clause Review for Interstate Coordinatio*n, 100 MINN. L. REV. 129, 189–97 (2015); James W. Coleman & Alexandra B. Klass, *Energy and Eminent Domain*, 104 MINN. L. REV. 659, 700–04 (2019); Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 VAND. L. REV. 1801, 1859–65 (2012); Jim Rossi, *The Trojan Horse of Electric Power Transmission Line Siting Authority*, 39 ENVTL. L. 1015, 1018–20 (2009); Klass & Rossi, *Federalism Battle*, *supra* note 212, at 435–44; Klass, *Crossroads*, *supra* note 212, at 1916–18; Brown & Rossi, *Siting Transmission Lines*, *supra* note 212, at 719–27; Zevin et al., *Building a New Grid*, *supra* note 212, at 182–89.

214 *See, e.g.* TEX. UTIL. CODE ANN. § 37.056(e) (West 2021) (stating that new lines "that directly [connect] with an existing electric utility facility . . . may be granted only to the owner of that existing facility"); NextEra Energy Capital Holdings, Inc. v. Lake, 48 F.4th 306 (5th Cir. 2022).

215 *See, e.g.*, ARK. CODE ANN. § 23-1-101(9)(A)(i) (2019) (defining public utilities as companies that "own[ ] or operat[e] in [Arkansas] equipment or facilities for . . . transmitting . . . power to or for the public for compensation"); *id.* § 23-3-201(a) (exempting existing utilities from certain siting regulatory requirements); Ethan Howland, *Customer Groups Seek to End Utility Lock on Transmission Development in MISO States*, UTIL. DIVE (July 25, 2022), https://perma.cc/72LB-KUQ4 ("Eight MISO states have ROFR laws, which block transmission developers from bidding against utilities for projects. Those states are Iowa, Indiana, Michigan, Minnesota, Montana, North Dakota, South Dakota and Texas, according to the complaint."). For a discussion of these siting rules, see Joshua C. Macey, *Zombie Energy Laws*, 73 VAND. L. REV. 1077, 1112–17 (2020).

216 Transmission planning has been the subject of less academic commentary. To my knowledge, there are only three academic analyses of transmission planning. In one,

and cost allocation rules disfavor the kind of long-range lines needed to support deep decarbonization. The first is that the primary federal regulation that establishes the process for transmission planning and cost allocation, FERC Order No. 1000,[217] gives utilities a strong incentive to build local lines and disincentivizes them from building regional and interregional lines that connect utility-scale solar and wind to demand centers. The second is that utilities may want to limit transmission capacity to reduce the competition their generators face.

Under Order No. 1000, transmission projects that are selected through regional or interregional planning processes have to use a competitive process to choose developers.[218] However, transmission projects that are constructed to meet local reliability needs are often exempt from that requirement.[219] This gives utilities an incentive to build local projects to bypass the competitive procurement process required for regional and interregional lines.[220] In recent years, the percentage of transmission development that goes to local projects has increased by a factor of three.[221] That provides some evidence that utilities are building local projects to avoid having to build regional ones.[222]

Professor Ari Peskoe points out that utilities have turned to local projects, quite possibly to avoid the competition they face in regional and interregional planning. *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 50–57 (2021) (arguing that RTOs "have supported the shift away from regional projects, which must be developed competitively, to smaller or supposedly time-sensitive projects that IOUs build with little oversight and without competitive pressures"); *see also* Alexandra Klass, Joshua Macey, Shelley Welton & Hannah Wiseman, *Grid Reliability Through Clean Energy*, 74 STAN. L. REV. 969, 1024–35 (2022); Lucas W. Davis, Catherine Hausman & Nancy L. Rose, *Transmission Impossible? Prospects for Decarbonizing the US Grid*, 37 J. ECON. PERSPS. 155, 166–67, 169–71 (2023) [hereinafter Peskoe, *Transmission Syndicate Forever?*].

217 F.E.R.C. Order No. 1000, Transmission Planning & Cost Allocation by Transmission Owning & Operating Public Utilities, 76 Fed. Reg. 49,842 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1000].

218 *See id.* at 49,897–98.

219 *See, e.g.*, PJM Interconnection, L.L.C., 142 F.E.R.C. ¶ 61,214, at ¶¶ 247–55 (2013) (authorizing exemptions from competition for certain lines needed within three years); ISO New England Inc., 143 F.E.R.C. ¶ 61,150, at ¶¶ 236–39 (Order on Compliance Filings 2013); ISO New England Inc., 150 F.E.R.C. ¶ 61,209, at ¶¶ 221–26 (Order on Rehearing and Compliance 2015) (affirming three-year period on rehearing); ISO New England Inc., 153 F.E.R.C. ¶ 61,012, at ¶ 44 (Order on Rehearing and Clarification and Compliance 2015) (reaffirming earlier orders exempting immediate-need reliability projects from competition).

220 *See* Peskoe, *Transmission Syndicate Forever?*, *supra* note 216, at 50–57.

221 *See id.* at 50.

222 There are, of course, other possible explanations. As discussed below, opposition to regional projects may reflect utilities' interest in protecting generator market power. It is also possible that regional projects get mired in bureaucratic delays, or that they face

Investing in local projects reduces the need for regional and interregional lines, and it does so despite the fact that it is usually more cost-effective to meet a region's transmission needs by building high-voltage direct current lines capable of transmitting large amounts of electric energy across large distances.[223] Regions that meet their reliability needs through the construction of local lines are typically reluctant to support regional projects—despite the fact that the regional projects would be more cost-effective, improve system reliability, and increase deployment of low-carbon resources.[224]

There is evidence that investment in local transmission projects has increased since Order No. 1000. Before Order No. 1000 went into effect, local transmission lines and local transmission upgrades accounted for approximately 30% of total spending on transmission. Today that number has ballooned to 90% in some markets.[225] Utilities may have turned to local lines to inflate their rate base and avoid competing with merchant developers for new projects.[226]

Another explanation for transmission owners' reluctance to build regional and interregional transmission lines is that they are trying to protect their generators' market power. Some transmission owners also own generators in areas of the country where transmission congestion allows them to exercise market power. Reducing grid congestion also reduces the market power of electric generators in transmission-constrained regions.[227] These

larger opposition in the siting process, or that all these factors contribute to the difficulties in building regional or interregional lines.

[223] *See* DEV MILLSTEIN, RYAN WISER, WILL GORMAN, SEONGEUN JEONG, JAMES KIM & AMOS ANCELL, LAWRENCE BERKELEY NAT'L LAB'Y, EMPIRICAL ESTIMATES OF TRANSMISSION VALUE USING LOCATIONAL MARGINAL PRICES (2022) [hereinafter MILLSTEIN ET AL., EMPIRICAL ESTIMATES OF TRANSMISSION VALUE]; *see also* JOHANNES PFEIFENBERGER, JUDY CHANG & MICHAEL HAGERTY, THE BRATTLE GROUP, COST SAVINGS OFFERED BY COMPETITION IN ELECTRIC TRANSMISSION (2019) [hereinafter PFEIFENBERGER ET AL., COST SAVINGS OFFERED BY COMPETITION IN ELECTRIC TRANSMISSION].

[224] *See* MILLSTEIN ET AL., EMPIRICAL ESTIMATES OF TRANSMISSION VALUE, *supra* note 223, at 5.

[225] PFEIFENBERGER ET AL., COST SAVINGS OFFERED BY COMPETITION IN ELECTRIC TRANSMISSION, *supra* note 223, at 11 (finding ninety-seven percent of transmission studied was not subject to competitive solicitations), Claire Wayner, *Increased Spending on Transmission in PJM—Is It the Right Type of Line?*, RMI exhibit 2 (Mar. 20, 2023), https://perma.cc/KGS3-QUCR.

[226] *See* Peskoe, *Transmission Syndicate Forever?*, *supra* note 216, at 50–57.

[227] *See* Hui He, Zheng Xu & Gaihong Chen, Impacts of Transmission Congestion on Markets Power in Electricity Markets 3 (Oct. 2004) (IIEE PES Power Sys. Conf. and Exposition paper) (on file with author).

vertically integrated utilities have little incentive to build transmission that would force their generators to compete with other resources.

While it is difficult to prove conclusively that utilities' reluctance to build regional transmission lines is based on their interest in protecting their generators' market power, there is circumstantial evidence that supports this view. One example that is consistent with this theory is Entergy's persistent opposition to transmission developments that would increase connections between New Orleans and MISO-North.[228] Entergy is a vertically integrated utility that provides generation, transmission, and distribution services to much of the South, including New Orleans. Entergy joined MISO in 2013 as part of a settlement with the Department of Justice.[229] The DOJ had initiated an antitrust investigation against Entergy because it was concerned that Entergy was using its control over transmission infrastructure to shield its generating assets from competition.[230] The DOJ agreed to drop its suit if Entergy joined an RTO.[231] Entergy now makes up most of MISO-South. Since 2013, MISO has not managed to build a single regional transmission line or a single new seam connecting MISO-North to MISO-South. Open-records requests have revealed that Entergy is worried about increasing penetration from renewables.[232]

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[228] For a terrific analysis of Entergy's incentives, see Catherine Hausman, *Power Flows: Transmission Lines, Allocative Inefficiency, and Corporate Profits* 25–27 (Nat'l Bureau of Econ. Res., Working Paper No. 32091, 2024).

[229] Interestingly, Entergy joined MISO despite the fact that independent analyses indicated that there would be more economic benefits if Entergy joined SPP. Most of those savings arose from the fact that there were more connections with SPP and thus more opportunities to import power. *See SPP Is the Best Choice for Entergy and Arkansas Ratepayers*, SW. POWER POOL (July 12, 2011), https://perma.cc/P6ED-UA74:

> [An SPP study] found that Entergy joining SPP would bring net benefits of $1.3 billion from 2013–2022 for all ratepayers in the SPP/Entergy region. According to a subsequent [Charles River Associates] cost-benefit study of Entergy joining MISO, benefits to the Entergy region are about $130 million higher if Entergy joins SPP.

[230] *See Justice Department Statement on Entergy Corp.'s Transmission System Commitments and Acquisition of KGen Power Corp.'s Plants in Arkansas and Mississippi*, U.S. DEP'T JUST. (Nov. 14, 2012), https://perma.cc/5MR3-BSNY.

[231] *Id.*

[232] *See* Email from Vishwas Sankaran, Transmission Econ. Plan. Manager, Entergy, to David Carr, Special Couns. to the Comm'n for Fed. Energy Affs., Miss. Pub. Serv. Comm'n (Nov. 3, 2019) (on file with author) (expressing concern "around the amount of renewable penetration they are targeting with these futures").

Entergy has relied on transmission constraints to justify building new gas-fired power plants. When other utilities in MISO introduced studies in MISO stakeholder meetings to support proposals to build new transmission, Entergy strongly opposed these new transmission developments and argued that the region did not face reliability problems. Yet when Entergy has asked the Louisiana Public Service Commission for approval to build new combined-cycle gas plants, it relied on the exact same studies to show that transmission congestion had contributed to power outages in New Orleans. In one notable example, Entergy hired actors to attend a PUC meeting to express their opposition to regional transmission lines and support for a $210 million new generating unit.[233] Thus, Entergy has opposed transmission lines that would improve reliability and invoked the region's lack of transmission to justify constructing costly new generating units.

Entergy's approach to transmission planning suggests that the company is investing in generation to obviate the need to build new transmission lines. In 2020, MISO announced plans to build a regional line that would increase import capacity between MISO-North and MISO-South. The line was expected to cost $108 million and have a benefit-to-cost ratio of three-to-one.[234] The following year, Entergy included a $870 million combined-fire gas plant in its integrated resource plan. It then challenged MISO's benefit-to-cost calculation for the transmission line. MISO then determined that the line was no longer needed. It found that, because the new generating unit would render unnecessary many of the reliability benefits of the transmission line, the line's benefit-to-cost ratio declined to just over one. In other words, Entergy built a $870 million generator to resolve reliability needs that could have been resolved by building a $130 million transmission line.[235]

Entergy's behavior does not appear to be atypical. When FERC requested comments on transmission planning reforms, all thirty-six utilities that still own generators submitted comments opposing reforms that would reduce barriers to regional

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233 *See* Michael Isaac Stein, *Actors Were Paid to Support Entergy's Power Plant at New Orleans City Council Meetings*, THE LENS (May 4, 2018), https://perma.cc/US4F-7TDG.

234 *See* Comments of S. Renewable Energy Ass'n at 9–10, Building for the Future, 87 Fed. Reg. 26,504 (proposed May 4, 2022), https://perma.cc/2U6F-9XBQ.

235 *See id.* at 10.

planning.[236] Utilities in vertically integrated markets have begun running television ads opposing market reforms that would lead to more regional transmission lines.[237]

The final issue is that lack of oversight of local projects allows utilities to build the projects that favor their own financial interests without going through the regional planning process. Some states carefully review transmission expenses. Others offer virtually no oversight of transmission costs. Moreover, states may be unable to assess whether lines that cross state boundaries could cost-effectively meet their transmission needs, and it is not clear that a state could unilaterally force utilities to consider whether transmission lines that connect to multiple states would better meet the states' transmission needs. As a result, even if every state carefully reviewed local transmission decisions, jurisdictional limits would still create a need for some oversight beyond the state level.

FERC recognized these challenges in Order No. 2000,[238] when it said,

> a single entity must coordinate these [transmission planning] actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability.[239]

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236 Utilities across the country oppose regional transmission solutions—seemingly to protect their market power and avoid having to compete with merchant transmission developers. *See* F.E.R.C. Order No. 890, Preventing Undue Discrimination and Preference in Transmission Serv., 72 Fed. Reg. 12,266, 12,318 (Mar. 15, 2007) (codified at 18 CFR pts. 35, 37) (stating that transmission owners lack an incentive to: (i) "relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive" or (ii) "increase the import or export capacity of [their] transmission system[s] if doing so would allow cheaper power to displace [their] higher cost generation or otherwise make new entry more profitable by facilitating exports"). *See generally* Pre-Technical Conference Statement of Nicholas J. Guidi on Behalf of the S. Envtl. L. Ctr., Tech. Conf. on Transmission Plan. & Cost Mgmt., No. AD22-8-000 (FERC Sept. 16, 2022).

237 *See* Kelly Roache, *Who Is Behind Anti-Regional Transmission Organization Ads in the Southeast?*, ENERGY & POL'Y INST. (Aug. 18, 2020), https://perma.cc/BD6B-7R2T.

238 F.E.R.C. Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 810, 909 (Jan. 6, 2000) (codified at 18 C.F.R. pt. 35); *accord* F.E.R.C. Order No. 2000-A: Regional Transmission Organizations, 65 Fed. Reg. 12,088 (Mar. 8, 2000) (reaffirming Order No. 2000 after rehearing); Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash. v. FERC, 272 F.3d 607 (D.C. Cir. 2001) (upholding these orders).

239 *Id.*

The regulatory gap for local planning, however, means that the United States is making haphazard investment decisions without considering whether new lines are needed or whether more cost-effective alternatives are available.

When states do not carefully assess whether local projects are needed, the only meaningful regulatory scrutiny comes from RTOs. But RTOs provide virtually no oversight of local transmission projects. Consider PJM's M-3 process, which comprises supplement projects that are built outside of the regional planning process. PJM does not actually approve M-3 projects. PJM approves only reliability and baseline projects. For M-3 projects, TOs are simply required to explain why they are developing a particular project. They issue a needs statement. The TO might say that the line is old, or that load growth or transmission congestion creates a need for additional transmission capacity, or that the line will improve operational flexibility. These statements often provide little information about whether—or why—the project is needed, often not explaining: what reliability violations justified the new line, how the line's performance compares to that of other lines, or whether and why the line is a priority. For example, in a 2022 stakeholder meeting, a PJM transmission owner explained that a supplemental project was needed because it would support "[o]perational [f]lexibility and [e]fficiency."[240] In another example from the same stakeholder meeting, the transmission provider simply said that a transmission line has "experienced operational issues."[241] Neither explained: what criteria the outages violated, how the line's performance compares to other lines, whether and why this line was a priority, or any other relevant material information.[242]

TOs also help determine the models used in local planning rather than in regional planning. That is because TOs have developed TO-specific models to justify needs for local projects but must rely on the models used by regional planning entities and RTOs when they participate in Order No. 1000 projects.[243] TOs need not make their criteria public. The onus is therefore on interested parties to ask questions about why the project is needed

240 PJM, PJM IDENTIFIED ISSUES AND PLANNED SOLUTIONS NEAR THE MISO SEAM: 4TH QUARTER REVIEW 2022, at 254 (2023).

241 *See id.* at 257.

242 *Id.* at 254, 257.

243 *See* PJM TRANSMISSION OWNERS, ATTACHMENT M-3 PROCESS GUIDELINES 7–9 (2022) (available at https://perma.cc/4FRP-ZT7E).

or whether a more cost-effective solution is available. Doing so is difficult, however, because TOs do not have to respond to these requests, and when they do respond, their responses often fail to provide enough detail to determine whether there is a genuine need for the project, or whether alternative lines would more cost-effectively meet those needs.

PJM's review of supplemental transmission projects is also inadequate. PJM applies a "do no harm" analysis that measures whether selected supplemental projects will "result in other reliability criteria violations."[244] PJM also considers whether an existing "Baseline Reliability Project" already meets the identified need,[245] but it does not consider whether alternatives would more effectively meet the need, or whether the utility is taking adequate measures to control its costs. PJM therefore provides little scrutiny of a utility's decision to construct a specific project instead of an alternative. Nor does it provide much oversight of whether the utility is taking sufficient steps to control its costs. PJM simply makes sure that the project will not undermine system reliability or create redundancies with transmission that has already been planned. The processes for reviewing local transmission in other RTOs are deficient for similar reasons.

FERC, too, does not adequately review local transmission projects. Because FERC applies a presumption of prudence to most new lines, it creates a default assumption that costs incurred to pay for local projects are just and reasonable. That assumption applies even when no other regulator scrutinized whether transmission expenditures are in fact prudently incurred. As a result, many of these lines are constructed despite the fact that no regulator assessed whether the lines are in the public interest.

Local lines also often receive little administrative oversight from PUCs. For example, in California, lines that are more than 230 kilovolts (kVs) have to receive a certificate of public convenience and necessity whereas lines that are less than 230 kVs, or that replace existing lines, must simply apply for a permit but are not reviewed. Between 2019 and 2021, 63% of transmission capacity in California was self-approved and did not undergo

[244] *See* Report of Sr. Transmission Regulatory Specialist Amber Thomas on Supplemental Projects Planning Process at 6, Petition of Ind. Mich. Power Co., 2020 WL 1656243 (Ind. Util. Regul. Comm'n Apr. 12, 2019) (No. 45235).

[245] *See id.*

regulatory review by CAISO, FERC, or the California Public Utility Commission.[246] This, too, does not appear to be unusual.[247]

Although there are many plausible explanations for the challenges the United States has faced building regional and interregional transmission lines, the analysis above shows that many utilities have a financial interest in blocking transmission projects that threaten their economic interests, and that the laws and regulations governing siting and transmission planning empower them to protect those interests.

B. Filing Rights, Jurisdictional Gaps, and Localism in Transmission Planning

One reason utilities can circumvent federal regulations aimed at encouraging regional transmission planning with competitive solicitations is that they have used their filing rights—which grant them unilateral authority to build certain projects needed to meet grid needs.

Consider again the Southeastern Regional Transmission Planning (SERTP), which plans transmission development in the Southeast, is entirely controlled by vertically integrated utilities that own nearly all the generation and transmission in the Southeast.[248] SERTP has never developed a single regional transmission. Instead, it has simply accepted proposals developed by the utilities that have a monopoly in the Southeast. If utilities in the Southeast and Pacific Northwest do not want to build more transmission, it is extremely difficult to get them to do so. That appears to be the case because these utilities designed regional planning processes that were entirely under their own control.

What is most surprising, however, is that utilities also manage to build nearly all new transmission projects, and to do so outside of the regional process, even where RTO ostensibly require regional planning. One reason for this is likely that transmission operators control subcommittees responsible for developing regional plans. In PJM, for example, regional transmission plans are proposed by the Transmission Expansion Advisory Committee (TEAC) and approved by the PJM Members

[246] *See* Testimony of Simon Hurd, Program & Project Supervisor, Energy Div., Calif. Pub. Utils. Comm'n, Transcript at 81, Tech. Conf. on Transmission Plan. & Cost Mgmt., No. AD22-8-00 (FERC Oct. 6, 2022).

[247] *See infra* Appendix.

Committee. TEAC consists of TOs,[249] and the Members Committee consists of five groups: generation owners, TOs, other suppliers, electric distributors, and end-use customers. It makes decisions by a majority vote. None of the five groups that makes up the Members Committee, with the possible exception of the End Users group, represents potential market entrants. In PJM, therefore, incumbents that have an interest in limiting generator competition also make decisions about whether to build regional transmission lines needed to increase competition and bring renewables to market. The other RTOs and regional transmission planning entities also have governance arrangements that favor incumbents.[250]

But control over regional transmission planning is not the only reason utilities have found ways to use transmission planning to benefit themselves. In fact, FERC has sometimes intervened to prevent TOs from controlling regional transmission planning. For example, in response to ISO-NE's Order No. 1000 compliance filing, FERC raised concerns about ISO-NE's plan to exclude nonincumbent developers from the ISO's "Needs Assessment Study Group."[251] In response, ISO-NE agreed "to eliminate the Needs Assessment Study Groups and instead allow any interested stakeholder to participate in the full Needs Assessment process through the Planning Advisory Committee."[252] The Planning Advisory Committee oversees regional planning and accepts members from a variety of market actors, including generator owners, marketers, LSEs, participating TOs, governmental representatives, retail customers, public interest groups, and consultants.[253]

Once again, utilities' filing rights equip them to carve out exceptions from regional transmission planning processes that have allowed them to unilaterally make investment decisions, and to do so by investing in local lines that avoid competition, protect their market power, and avoid regulatory oversight. For example, when approving ISO-NE, FERC considered that TOs would be able to use their § 205 filing rights to exercise undue influence

[249] *See generally* PJM, TRANSMISSION EXPANSION ADVISORY COMMITTEE (TEAC) CHARTER (2011).

[250] *See, e.g.*, N. Tier Transmission Grp., Order No. 1000 Attachment K Joint Compliance Filing at 3, Elec. Rate Filings, No. ER13-65-000 (F.E.R.C. Oct. 10, 2012).

[251] 143 F.E.R.C. ¶ 61,150, at pp. 62,045–46 (Order on Compliance Filings 2013).

[252] 150 F.E.R.C. ¶ 61,209, at p. 62,440 (Order on Rehearing & Compliance 2015).

[253] *See Planning Advisory Committee*, ISO-NE, https://perma.cc/Z4GG-B7JK.

over transmission planning. However, because FERC was ultimately unable to force utilities to relinquish their filing rights, the TOs retained significant authority over their own revenue requirements.[254] Further, TOs would have authority to "submit section 205 filings to establish and revise the rates and charges for transmission service under the RTO-NE OATT [Open Access Transmission Tariff] and the rates, terms and conditions relating to incentive or performance-based rates."[255] ISO-NE was also required to consult with the TOs to determine whether a filing would have adverse impacts on TOs' revenue requirements.[256] FERC accepted this proposed allocation of section 205 filing rights.[257]

Thus, New England TOs proposed a regional transmission planning process that preserved significant authority for themselves—not least authority over local plans. Even though FERC pushed back against this governance proposal in some respects, notably over the composition of a board that advised regional planning, it eventually accepted a plan that preserved utilities' control over local planning.

Similar dynamics have played out in other RTOs. In New York, for example, TOs also develop their own planning criteria for local projects.[258] Here, too, investment in local projects can obviate the need for regional plans. In PJM, utilities retain filing rights related to local transmission projects.[259] In these markets, therefore, incumbent control over local planning occurred because FERC was forced to negotiate with incumbent utilities, who insisted on retaining this control.

Notably, when FERC was reviewing Order No. 1000 compliance filings, one of its primary concerns was that supplemental projects would receive insufficient review and therefore offer a workaround to regional planning.[260] A related concern was that

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[254] *See* ISO New Eng. Inc. v. New Eng. Power Pool, 106 F.E.R.C. ¶ 61,280, at p. 62,029–30 (2004).

[255] *Id.* at p. 62,030.

[256] *See id.* at p. 62,031.

[257] *See id.* at p. 62,032.

[258] *See, e.g.*, Attachment Y–New York ISO Comprehensive System Planning Process at *428, *447, § 205(d) Rate Filing: Original ISA/CSA, Serv. Agreement, Docket No. ER23–1151–000 (FERC 2023).

[259] *See, e.g.*, PJM, CONSOLIDATED TRANSMISSION OWNERS AGREEMENT 74 (2013).

[260] ISO New Eng. Inc., 143 F.E.R.C. ¶ 61,150, at pp. 62,045–46 (Order on Compliance Filings 2013) (expressing concern about ISO-NE's Needs Assessment Study Group—a group that would have been within ISO-NE's transmission Planning Advisory Committee—for excluding nonincumbent developers and thus making it "more difficult for such

the planning process would exclude competitors or otherwise give incumbent transmission owners too much control over regional planning.[261] A stark example of this is FERC's skepticism about SERTP's initial Order No. 1000 filings. In response to SERTP's first filing, FERC expressed concern that: SERTP's membership criteria excluded merchant developers, incumbents would control the regional planning process, and investments in local projects would erode the need for regional transmission solutions. SERTP initially proposed that enrollment be limited to entities with "a statutory or OATT obligation."[262] This requirement would have "prohibit[ed] an entity that wishes to voluntarily enroll in the SERTP region from doing so, if that entity does not have a statutory or OATT obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region."[263] SERTP, in other words, proposed that utilities that already had an obligation to provide transmission service in the Southeast be the only entities eligible for membership in SERTP. FERC also remarked that it is "unclear from Filing Parties' OATTs whether the transmission providers in the SERTP region will conduct their own regional analysis as part of each planning cycle, or whether they may rely solely on transmission developers to propose more efficient and cost-effective transmission solutions."[264]

Eventually, the filing parties revised their submission to clarify that they "will rely on the SERTP process for both local and regional transmission planning."[265] FERC largely approved this revision, though it remained concerned that SERTP parties had not revised their tariffs "to provide stakeholders sufficient information to understand which aspects of the SERTP procedures apply to the local transmission planning process and which apply to

[nonincumbent] developers to propose transmission projects than it would be if they were permitted to participate"); PJM Interconnection, 142 F.E.R.C. ¶ 61,214, at pp. 62,295–97 (Order on Compliance Filings 2013) (expressing concern about exempting Immediate-need Reliability Projects from competitive solicitations and imposing criteria to prevent utilities from abusing this exemption).

261 N.Y. Indep. Sys. Operator, Inc., 148 F.E.R.C. ¶ 61,044, at p. 61,221 (Order on Rehearing and Compliance 2014) (expressing concern with NYISO's proposal that transmission owners, not NYISO, determine which transmission facility was selected in the regional plan); N.Y. Indep. Sys. Operator, Inc., 153 F.E.R.C. ¶ 61,341, at p. 63,196 (Order Conditionally Accepting Tariff Revisions & Requiring Further Compliance 2015) (same).

262 Louisville Gas & Elec. Co., 144 F.E.R.C. ¶ 61,054, at p. 61,372 (Order on Compliance Filings 2013) [hereinafter SERTP First Order].

263 *Id.* This issue was resolved in the second filing, wherein the filing parties removed this requirement. *See* SERTP Second Order.

264 SERTP First Order, 144 F.E.R.C. at p. 61,379.

265 SERTP Second Order, 147 F.E.R.C. at p. 62,515.

the regional transmission planning process."[266] The question of who would actually perform transmission planning came up again in FERC's third order reviewing SERTP's Order No. 1000 filing, where FERC ultimately accepted SERTP's proposal that "each [TO] perform their local transmission expansion planning concurrently with the development of the SERTP regional transmission plan."[267] These, concerns, while prescient, did not succeed in preventing incumbents from controlling transmission planning in the Southeast. As explained in Part I.B, because SERTP simply accepts members' proposed transmission solutions, it has effectively outsourced Southeast transmission planning to incumbent utilities that have a financial interest in protecting their generating assets and ensuring that transmission solutions are local. Once again, utility filing rights allowed them to draft the rules for transmission planning, and they used that authority to write rules that favor their assets while limiting competition and driving up costs.

V. Solutions

U.S. electricity markets thus contain numerous features that allow market participants to design rules or make investment decisions that pass the costs of reliability and climate regulations onto their captive ratepayers. No single reform will solve all these challenges, but improving grid governance, liberalizing energy markets, and increasing administrative capacity would make it easier to administer price-based regulations.

A. Grid Governance Reforms

Many of the regulations described in this paper are simply bad policy. For example, there is no economic justification for eight-hour performance duration requirements that prevent storage resources from clearing capacity auctions. Nor is there any justification for allowing some firms to recover their fuel costs from captive ratepayers while forcing independent power producers to recover all their costs from energy and capacity markets.

Many of these rules appear rational, however, from a political economy perspective. RTOs are governed by incumbent firms. Control of RTO governance allows utilities to control

[266] SERTP Second Order, 147 F.E.R.C. at p. 62,515.

[267] Duke Energy Carolinas, 151 F.E.R.C. ¶ 61,021, at p. 61,212 (Order on Rehearing and Compliance 2015) [hereinafter SERTP Third Order].

transmission planning and cost allocation—and design electricity markets that provide hidden subsidies to fossil resources.[268] In addition, utilities' influence with their PUCs allows them to influence state policy (examples of agency capture in electricity markets are extreme[269]). And parochial siting laws allow utilities to hold up developments needed to bring renewables to market. Thus, the processes by which energy market rules are created give utilities ample opportunity to draft rules that favor their own interests.

Reforming grid governance could therefore be expected to reduce the number of rules that favor incumbent fossil resources. Grid governance should be reformed in two ways. First, RTOs and public utility commissions should represent the people they serve—not incumbent companies that sell electricity to consumers. This could be accomplished either through public ownership of RTOs or through more representative boards.[270]

Second, decision-making processes are often opaque. State ratemaking proceedings are usually confidential, and utilities frequently refuse to disclose their costs. This lack of transparency makes it difficult for customers and advocates to get involved with utility proceedings. For example, PacifiCorp, a utility in the Pacific Northwest, refused to disclose how much it was paying for coal.[271] PacifiCorp also owned the coal mines that sold coal to its Washington and Oregon coal-fired power plants. The company argued that it did not have to disclose this information because doing so would reveal trade secrets and put it at a competitive disadvantage.[272]

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[268] *See supra* Parts III–IV.

[269] *See, e.g.*, Jaclyn Diaz, *An Energy Company Behind a Major Bribery Scandal in Ohio Will Pay a $230 Million Fine*, NPR (July 23, 2021), https://perma.cc/9U5S-4E2W.

[270] The details of an optimal RTO governance framework are, however, beyond the scope of this paper. Welton has written extensively on this subject. *See generally, e.g.*, Welton, *Public Energy*, *supra* note 24; Welton, *Rethinking Grid Governance*, *supra* note 38.

[271] *See In re* PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan & 2019 Integrated Resource Plan, Nos. LC 67 & LC 70, at 3 (Or. Pub. Util. Comm'n Aug. 7, 2018) ("PacifiCorp maintains that this information qualifies as a protected 'trade secret or other confidential research, development, or commercial information' under ORCP 36(C) because disclosure could competitively disadvantage PacifiCorp and its customers in transactions relating to operating, maintaining, or transitioning or decommissioning its coal plants."); *see also id.* at 4 ("I find that the coal analysis satisfies both elements of a trade secret, because it has economic value in potential or actual transactions, and it is not public information.").

[272] *See id.* at 3.

This explanation is unconvincing, however, because PacifiCorp does not have any competitors. After years of litigation, the Sierra Club finally was able to force PacifiCorp to disclose its fuel costs. It turned out that 60% of PacifiCorp's coal units were uneconomic, and that the company was able to reduce costs and improve reliability by retiring all its coal assets.[273] Because rate regulation prevents customers from transacting for cheaper or cleaner electricity, robust disclosure requirements are an especially important way to improve agency oversight by increasing the capacity of private organizations to get involved in rate hearings.

Third, and perhaps most importantly, regulators should reconsider when to outsource grid regulations and when to implement regulations themselves. Of course, government entities are unlikely to construct new generating units or transmission facilities. Still, it is not clear why utilities help oversee the reliability auctions that determine how much they will be paid for supporting grid reliability. Nor is it clear why market participants conduct transmission planning that determines whether generators can connect to the market. Even if private companies should construct and maintain power plants and transmission facilities, public control over the various market processes that allocate revenue may be preferable to the status quo: in which private parties influence who will build projects and how much revenue they will make in doing so.

B. Market Liberalization and Full Corporate Unbundling

As discussed in Part IV, utilities have both the incentive and ability to invest in transmission that makes it more difficult for renewables to enter the market. In theory, utilities should want to build as much transmission as possible—they are, after all, allowed to rate base transmission—but that incentive is diminished because utilities have an incentive to avoid participating in planning processes that force them to compete with merchant developers, and because they are reluctant to protect the market power of their generation affiliates.

One way to correct this misalignment of incentives is to force transmission owners and LSEs to divest themselves of their

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[273] *See* Iulia Gheorghiu, *PacifiCorp Shows 60% of Its Coal Units Are Uneconomic*, UTIL. DIVE (Dec. 5, 2018), https://perma.cc/76BX-X9SG.

generation affiliates. FERC refrained from doing this in Order No. 1000 because it thought

> that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.[274]

But after twenty-five years, it is clear that functional unbundling has failed to prevent vertically integrated utilities from discriminating against independent power producers. If generators were not affiliated with LSEs, they would not be able to recover fuel costs in retail tariffs. Full corporate unbundling would also reduce transmission operators' incentive to avoid regional and interregional transmission developments, since they would have no reason to favor certain generators over others. Quarantining rate-regulated assets would therefore reduce conflicts of interest that render utilities less responsive to climate and reliability regulations.

At a more general level, the continued use of rate regulation is problematic because it allows utilities to pass costs directly onto their ratepayers. That happens both because: (i) generators in some parts of the country continue to be rate regulated, which makes it impossible for consumers to select their preferred resource mix, and (ii) because rate-regulated parts of the supply chain allow vertically integrated utilities to provide hidden subsidies to their generation units.

Further liberalizing electricity markets would therefore make it more difficult for utilities to pass their regulatory compliance costs to captive ratepayers. In 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) in which it proposed a standard design for electricity markets. This NOPR is known as the "standard market design" NOPR. It would have mandated RTO membership, given RTOs operational control over transmission throughout the entire country, and established transparent wholesale pricing.[275]

Requiring transparent price formation and forcing generators to compete on cost would increase utilities' responsiveness to

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[274] Order No. 888, 61 Fed. Reg. at 21,552.

[275] *See generally* Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55,452 (proposed Dec. 11, 2002).

the price impacts of climate and reliability policies, reduce the number of hidden utility subsidies that distort energy markets, and increase the ability of regulators to identify market manipulation. Enacting standard market design would therefore facilitate the implementation of climate and reliability policies—especially if regulators also mandated governance reforms and full corporate unbundling.

C. Improve Administrative Capacity

It is not clear that it would be possible, or even desirable, to fully liberalize U.S. electricity markets.[276] The costs of doing so would be significant, as would be the political pushback. It is therefore likely that significant amount of decarbonization will involve rate-regulated firms, many of which have little financial incentive to reduce emissions.

That makes it imperative that state PUCs have the resources and expertise to supervise the companies they regulate. Unfortunately, many state PUCs are understaffed. Consumer advocates have long argued that PUCs, especially in small states, struggle to attract qualified employees, and that staff positions remain vacant for years.[277] This problem is not limited to states. A FERC commissioner recently acknowledged that "[t]he reality is that the Commission does not have the capacity to open a section 206 investigation in every instance where an existing rate may be unjust and unreasonable or unduly discriminatory."[278] Because FERC and state PUCs authorize the expenditures of the company that will be responsible for decarbonizing the electric grid, deep decarbonization requires that they have the resources, staffing, and expertise to zealously regulate utilities.

In addition to resource and staffing concerns, administrative capacity is reduced when jurisdictional tensions make it difficult for regulators to supervise public utilities.[279] In the past twenty years, utility mergers have led to rapid industry consolidation.

[276] For an empirical argument showing that restructuring has been beneficial even though the implementation has been imperfect, see generally Steve Cicala, *Imperfect Markets Versus Imperfect Regulation in US Electricity Generation*, 112 AM. ECON. REV. 409 (2022).

[277] *See, e.g.*, Civil Beat Editorial Board, *Public Utilities Commission: Don't Short-Circuit Energy Regulation*, HONOLULU CIV. BEAT (Feb. 17, 2015), https://perma.cc/9LK6-RTVK.

[278] Order Accepting Proposed Tariff Revisions Subject to Condition, Midcontinent Indep. Sys. Operator, Inc., 180 F.E.R.C. ¶ 61,141, at p. 61,974 (2022) (Clement, Comm'r, dissenting).

[279] *See* Christiansen & Macey, *supra* note 67, at 1376.

Today there are half-as-many rate-regulated utilities as there were twenty years ago.[280] Many utilities have franchises in ten or more states. This can make it very difficult for any individual regulator to police utility misconduct. If, for example, Duke Energy's retail electric provider in North Carolina guarantees the debt of its generation assets in Virginia, it may be impossible for any individual regulator to determine whether this transaction is in the public interest.[281] The North Carolina PUC's jurisdiction is limited to retail sales in North Carolina. The Virginia Corporation Commission's jurisdiction is limited to retail sales in Virginia. And FERC can only regulate wholesale sales: it has no jurisdiction over retail sales. The result is that cross-affiliate financing arrangements may create a regulatory gap.

This all provides some support for additional FERC oversight. That does not mean that state energy laws should be preempted entirely, but it does suggest that it would be helpful to give FERC residual authority to fill regulatory gaps when no one regulator has authority to regulate cross-affiliate transactions that reduce the effectiveness of climate and reliability rules.[282]

CONCLUSION

A fundamental principle of economics is that regulations are effective because they affect incentives. Every single climate policy assumes that the costs of regulations will be borne, at least to some extent, by the firms that are subject to regulation. Unfortunately, the law and governance arrangements in electricity markets frequently allow market participants to develop market rules that allow them to pass the costs of complying with climate and reliability rules on to their captive ratepayers. To address these issues, policymakers should adopt a variety of technical reforms, such as further liberalizing electricity markets, mandating corporate unbundling, and improving administrative capacity—which would improve the effectiveness and administrability of climate and reliability policies. However, given the pervasive governance concerns that undermine climate and reliability policies, regulators should also consider taking a more proactive role in designing electricity markets and planning transmission investments.

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280 *See* SCOTT HEMPLING, REGULATING MERGERS AND ACQUISITIONS OF U.S. ELECTRIC UTILITIES: INDUSTRY CONCENTRATION AND CORPORATE COMPLICATION, at xxiii (2020).

281 *See* Joshua C. Macey, *Utility Mergers and the Modern (and Future) Power Grid*, 42 ENERGY L.J. 237, 243 (2021) (book review).

282 *See generally* Christiansen & Macey, *supra* note 67.

APPENDIX

This Appendix summarizes fuel adjustment clauses across the country. It shows that these clauses are pervasive and vary considerably.

State	**Regulation**
Alabama	Fully allows fuel adjustment clauses (FACs).[283] Rates are changed so that utilities always achieve the Alabama Public Service Commission's approved rate of return. Rate adjustments are not limited to responding to fuel costs but take into account all incurred allowable expenses (including taxes and some advertising expenses).[284] Rate changes cannot be challenged by ratepayers.[285]
Alaska	Fully allows FACs for fuel costs.[286]
Arizona	Fully allows FACs for fuel costs.[287] No markups are applied. Law requires that adjustment charges be listed separately on utility bills (adjustments were close to three cents per kilowatt-hour during winter 2023).[288]

283 *See* ALA. PUB. SERV. COMM'N, 2022 ANNUAL REPORT 26 (2022):

> Rate RSE is designed to lessen the impact, frequency and size of retail rate increase requests by permitting APC to adjust its charges periodically to provide a reasonable opportunity to achieve the rate of return allowed by the rate order of the Commission. Rate RSE is the rate approved by the Commission in Dockets 18117 and 18416.

284 *See generally, e.g.*, ALA. POWER, RATE RSE: RATE STABILIZATION AND EQUALIZATION FACTOR (8th ed. 2020).

285 *See* David Schlissel & Anna Sommer, ARISE CITIZENS' POLICY PROJECT, PUBLIC UTILITY REGULATION WITHOUT THE PUBLIC: THE ALABAMA PUBLIC SERVICE COMMISSION AND ALABAMA POWER 5 (2013).

286 *See* ALASKA ADMIN. CODE tit. 3, § 52.503(a) (2023) ("A cost-of-power adjustment (COPA) for an electric utility must provide for an adjustment, per kilowatt-hour of sales, equal to the difference between the utility's cost of power included in its base rates and the utility's projected cost of power . . . .").

287 *See* ARIZ. ADMIN. CODE § R14-2-210(b)(2)(g) (2022).

288 *Purchased Power and Fuel Adjustment Charge*, TUCSON ELEC. POWER, https://perma.cc/7V5B-3P5P.

Arkansas	Allows fuel adjustments.[289] However, price adjustments are not based solely on fuel procurement costs, but on "fees and other charges made by the wholesale power suppliers to the Company, cost for equity transfer for city energy, debt service associated by Company owned power generation, as well as company owned generation fuel and labor costs."[290]
California	Has FACs, but divides them into two systems: For large utilities, the California Public Utilities Commission (CPUC) employs Energy Resource Recovery Accounts (ERRAs) which are proceedings "used to determine fuel and purchased power costs which can be recovered in rates."[291] These "costs are forecast for the year ahead. If the actual costs are lower than forecast, then the utility gives money back, and vice versa."[292] This is a two-part process: 1. An annual ERRA forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the coming year. 2. An annual ERRA compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least-cost dispatch, fuel procurement, and the ERRA balancing account.

[289] *See* 126-03-1 ARK. CODE R. § 7.03(c)(1) (LexisNexis 2024).

[290] *Fuel Adjustment*, CLARKSVILLE CONNECTED UTILS., https://perma.cc/RCG7-ERKW.

[291] Cal. Pub. Utilities Comm'n, *What Is an Energy Resource Recovery Account (ERRA) Proceeding?*, CA.GOV (last updated 2021), https://perma.cc/ERS2-3CKJ; *see also* CAL. PUB. UTIL. CODE § 454.5(d) (West 2021).

[292] Cal. Pub. Utilities Comm'n, *supra* note 291; CAL. PUB. UTIL. CODE § 454.5(d).

	For smaller utilities, CPUC has the Energy Cost Adjustment Clause, (ECAC) which is supposed "to reflect all net power costs" which include fuel, purchased power, wheeling, and sales for resale except for net power costs not specifically modeled.[293] There does not appear to be any explicit provision in the CPUC's code authorizing the ECAC, but there are individual filings each year for each utility company where their proposed adjustments get approved. They refer to annual filings, so it is likely the CPUC must give approval every year.[294] This may provide more opportunities for oversight.
Colorado	FACs but appears to be aware of the challenges they provide. The state passed an act in 2023 stating that "[o]n or before January 1, 2025, the commission shall adopt rules to establish mechanisms to align the financial incentives of an investor-owned electric or gas utility with the interests of the utility's customers regarding incurred fuel costs."[295] In that same act, they said that the commission should consider "[s]ymmetrically allocating an amount of fuel price risk to the investor-owned electric or gas utility."[296]
Connecticut	Has FACs. The Connecticut Public Utilities Regulatory Authority states that "[n]o adjustment clause . . . shall be authorized . . . if such a clause operates automatically to permit charges . . . to existing rate schedules to be made which have not been first approved by the authority."[297] However, it also states that "[t]he Public

[293] PAC. POWER & LIGHT CO., SCHEDULE ECAC-94: ENERGY COST ADJUSTMENT CLAUSE TARIFF RATE RIDER 1 (2022).
[294] *See, e.g.*, LIBERTY UTILS. CALPECO ELEC. LLC, PRELIMINARY STATEMENT § 6 (2021).
[295] COLO. REV. STAT. § 40-3-120(2)(a) (2023).
[296] *Id.* § 40-3-120(3)(a)(I).
[297] CONN. GEN. STAT. § 16-19b(a) (2017).

	Utilities Regulatory Authority shall adjust the retail rate charged by each electric distribution company for electric transmission services periodically to recover all transmission costs prudently incurred by each electric distribution company."[298] Hence, a prior hearing is required, but fuel adjustment does occur.
Delaware	Has an FCA (called Procurement Cost Adjustment, or PCA) that was instituted in 2007.[299] It is set to "reflect the difference between the actual cost of serving customers in each fixed price [standard offer service] customer group and the amount billed to fixed price [standard offer service] customers for the same time period, plus interest at a rate equal to the Company's overall return."[300] The interesting part here is that an interest rate is charged "equal to the Company's overall return"—so if the utility did particularly well, that is reflected in higher rates for consumers.
Florida	Fuel clause hearings are conducted annually and are based on projected fuel and capacity-related service costs.[301] These costs are then recovered to "true-up" the charges through a surcharge. However, if cost-recovery position is set to exceed the projected costs by 10% or more, a mid-course correction hearing is triggered.[302] Then, electricity rate charges can be increased midway through the year.

[298] *Id.* § 16-19b(d).

[299] *See* DELMARVA POWER & LIGHT CO., THE DELAWARE ELECTRIC TARIFF 112 (2023).

[300] *Id.*

[301] *See generally* Order Approving Florida Power & Light Company's Petition for Mid-Course Correction, *In re* Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor, No. 2021001-EI (Fl. Pub. Serv. Comm'n Apr. 21, 2021) (approving Florida Power & Light Co.'s mid-course correction of fuel cost recovery factors).

[302] *See* FLA. ADMIN. CODE ANN. r 25-6.0424 ("[N]otification of a 10 percent or greater estimated over-recovery or under-recovery shall include a petition for mid-course correction to the fuel cost recovery or capacity cost recovery factors, or shall include an explanation of why a mid-course correction is not practical.").

Georgia	Utilities are allowed to recover 100% of incurred fuel costs.[303] Rates can be adjusted by up to 40% to allow for recovery,[304] but utilities must get approval from the commission and cannot automatically increase rates.[305] Commissioners appear to authorize every request.[306]
Hawai'i	Has FACs *with risk sharing*. Unlike in some other states, Hawai'i allows for increases or decreases in rates without any prior hearing.[307] However, utilities must still file notice with the utilities commission of any rate changes.[308] In 2018, Hawai'i's Public Utilities Commission required the largest electric utility (Hawaiian Electric Company) to share some of the costs of fossil fuels, rather than passing on 100% of the costs to consumers. The risk-sharing remains modest: it is currently a 98%/2% split (with consumers shouldering the 98%), with an annual exposure cap of $2.5 million.[309] That amount is fairly insignificant given that the Electric Company had about $2.5 billion in revenues in 2022, and a net income of $190 million.[310] This split appears to have taken effect in 2023.

303 *See* GA. CODE ANN. § 46-2-26 (2022).

304 *See* Ga. Power, *2023 Fuel Cost Recovery* (2023), https://www.georgiapower.com/company/filings/fuel-cost.html.

305 GA. CODE ANN. § 46-2-26.

306 *See* Jeff Amy, *Georgia Power Bills Likely to Rise by 12% in June*, ASSOCIATED PRESS (Apr. 24, 2023), https://perma.cc/YU94-75GL.

307 *See* HAW. CODE R. § 6-60-6(1) (LexisNexis 1981).

308 *See id.* § 6-60-6(5).

309 *See* Order No. 35545 at 3, *In re* Application of Hawaiian Elec. Co. for Approval of Gen. Rate Case and Revised Rate Schedule/Rules, No. 2016-0328 (Haw. Pub. Utils. Comm'n June 22, 2018).

310 *See* HAWAIIAN ELEC. CO., ANNUAL REPORT OF HAWAIIAN ELECTRIC COMPANY, INC. FOR THE YEAR ENDED 12/31/2022, at 114–15 (2023).

Idaho	Has FACs.[311] Idaho allows adjustments both for fuel costs[312] and for fixed costs.[313] However, the Idaho Public Utilities Commission has ordered utilities to credit a share of their profits to fuel adjustment costs if returns fall above a 10% return on equity.[314]
Illinois	Has FACs, but rate changes must be authorized by the Commission.[315] A notable feature of the Illinois law is that it allows the Public Utilities Commission to "authorize the increase or decrease of rates and charges based upon expenditures or revenues resulting from the purchase or sale of emission allowances created under the federal Clean Air Act Amendments of 1990, through such fuel adjustment clauses, as a cost of fuel."[316] This appears to further reduces any incentives utilities may have to pursue renewables, since they can pass emission costs and fuel costs straight to consumers.
Indiana	Allows FACs that automatically adjust rates, without commission input (save for the initial approval of the FAC) for nonmunicipally or cooperatively owned utilities.[317] For municipally or cooperatively owned utilities, commission approval is required prior to a rate change for costs, and the law prescribes that

311 *See* IDAHO ADMIN. CODE r. 31.01.01.122(2) (2023).

312 *See* IDAHO PUB. UTILS. COMM'N, TARIFF NO. 29: GENERAL RULES, REGULATIONS AND RATES, at sched. 55 (2023).

313 *See id.* at sched. 54.

314 *See id.* at sched. 55; *see also* Order No. 33149, *In re* Idaho Power Co.'s Application to Extend Its Revenue Sharing Mechanism Beyond 2014, (Idaho Pub. Utils. Comm'n Oct. 9, 2014) (No. IPC-E-14-14):

> [I]f the Company's actual annual return on equity . . . exceeds 10% . . . the Company will reduce customer rates in the next power cost adjustment ("PCA") by 75% of the amount from the 10%-10.5% ROE . . . if the Company's annual Idaho ROE exceeds 10.5% . . . , the Company will: (a) reduce customer rates in the next PCA by 50% of all amounts above the 10.5% ROE; and (b) use 25% of the amount above the 10.5% ROE to offset amounts in the Company's pension balancing account that customers would otherwise pay through rates.

315 *See* 220 ILL. COMP. STAT. § 5/9-220 (2017).

316 *Id.* § 9-220(a).

317 *See* IND. CODE § 8-1-2-42 (2023).

	"the utility consumer counselor shall examine the books and records of the public, municipally owned, or cooperatively owned generating utility to determine the cost of fuel upon which the proposed charges are based."[318] Also, fuel charges may not change more often than every three months, and a utility must make "every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible."[319]
Iowa	Has FACs that seemingly automatically adjust rates without hearing. The clause is called "Electric energy *automatic* adjustment," but it requires that "[p]rior to any period in which a utility proposes to change the adjustment amount for each energy unit delivered to the customer, the utility shall determine and file for board approval the adjustment amount to be charged for each energy unit delivered under rates set by the board."[320] Despite the name, it is unclear to whether the adjustment is automatic.
Kansas	Has FACs. Utilities estimate their fuel costs quarterly. On an annual basis, the Kansas Corporation Commission conducts a true-up audit to verify the accuracy of the costs and make adjustments if estimates were too high or low.[321]
Kentucky	Has FACs that change monthly to reflect fuel costs incurred two months earlier.[322] Monthly FAC filings are reviewed by the Kentucky Public Service Commission (KPSC) for accuracy, and a more detailed audit is undertaken

318 *Id.* § 8-1-2-42(b).

319 *Id.*

320 IOWA ADMIN. CODE r. 199-20.9(2) (2021) (emphasis added).

321 *See* KAN. CO. COMM'N, DECODING YOUR ELECTRIC BILL (2022).

322 807 KY. ADMIN. REGS. 5:056 (2021); KY. PUB. SERV. COMM'N, THE FUEL ADJUSTMENT CLAUSE: FREQUENTLY ASKED QUESTIONS.

	every six months. A final review occurs at two-year intervals.[323] Recent concerns about large rate increases has led the KPSC to open a proceeding "to investigate the fuel adjustment clause, purchased power cost recovery, current and future fuel and power price volatility, and related cost recovery mechanisms."[324] The Commission accurately stated that "[i]f a generator is essentially guaranteed to recover the costs related to non-economy purchases or forced outages, it raises the question of whether utilities will pursue the lowest cost and most efficient fuel procurement, or whether they will employ reasonable operational and maintenance practices."[325] In response, "the Commission question[ed] the working expectation that FAC charges are presumed reasonable absent evidence to the contrary."[326] Moving forward, "[t]he Commission will seek comment on whether utilities should be required to file additional evidence relating to the reasonableness of their FAC charges and purchased power expense. This evidence could include, but not be limited to, economic dispatch practices; RTO bidding practices and decisions; power plant maintenance; and comparing fuel and power purchase costs to area averages."[327]
Louisiana	Has FACs (and the regulation implementing them has not been changed since 1997).[328] Utilities may pass on costs without seeking Commission review, but "regulators retain

323 KY. PUB. SERV. COMM'N, *supra* note 322.

324 Order at 1, *In re* Elec. Investigation of the Fuel Adjustment Clause Regul., No. 2022-00190 (Ky. Pub. Serv. Comm'n 2022).

325 *Id.* at 8.

326 *Id.* at 10.

327 *Id.*

328 *See generally* General Order on Fuel Adjustment Costs, *In re* Dev. of Standards Governing the Treatment and Allocation of Fuel Costs by Elec. Util. Cos., (La. Pub. Serv. Comm'n Oct. 1, 1997) (No. U-21497).

	jurisdiction to review and determine, after the fact, whether the costs passed through to consumers via such clauses were prudently incurred."[329] The order does have a very clear list of what types of costs are acceptable and which are not.[330]
Maine	Does *not* have FACs—repealed in 1999.[331]
Maryland	Has FACs that allow utilities to independently pass costs along to customers, without first seeking Commission approval. However, utilities must "verify and justify the adjusted costs to the Commission each month," and the Commission can find them unjustified ex post.[332] However, in practice Maryland has deregulated its electricity industry, and today costs are just recovered on a current basis (i.e., flexible rate contracts).[333]
Massachusetts	Does not have FACs. Deregulated the energy sector and rates for basic service are market-based.[334]
Michigan	Allows FACs. However, utilities must file a proposed adjustment amount with the Michigan Public Service Commission together with receipts showing costs of fuel, projections about future load, its anticipated suppliers, and other matters related to its procurement cots,[335] before changing rates. If the Commission does not rule on the proposed adjustment within three months, "then pending an order that determines the power supply cost recovery factors, a utility may each month adjust its rates to incorporate all or a part of the power supply cost recovery factors

329 *Id.* at 3.
330 *See id.* at 8–9.
331 *See* ME. STAT. tit. 35-A, § 3101 (repealed 1999).
332 MD. CODE ANN., PUB. UTIL. § 4-402(b) (LexisNexis 2021).
333 MKT. INTEL, S&P GLOB., RRA REGULATORY FOCUS: ADJUSTMENT CLAUSES 26 (2017).
334 *See id.*
335 *See* MICH. COMP. LAWS § 460.6j(2)–(4) (2016).

	requested in its plan."[336] However, "[a]ny amounts collected under the power supply cost recovery factors before the commission makes its final order is subject to prompt refund with interest to the extent that the total amounts collected exceed the total amounts determined in the commission's final order to be reasonable and prudent for the same period of time."[337]
Minnesota	Allows FACs that automatically recover costs for fuel and "prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates."[338] Though not as extreme as the provision in Illinois (which allowed rate adjustments for emission charges), this also appears to remove incentives for Minnesota utilities to pursue green energy.
Mississippi	Has FACs, but originally recovery was allowed only for "the actual cost of the fuel and its transportation."[339] The state public utility commission must review fuel purchases and recovered costs no less than once per year.[340] *However*, the Mississippi code allows the Mississippi Public Service Commission to allow recovery for additional costs, and the Commission has included "[t]he actual costs of SO_2 and NO_X emission allowances, required by Federal or State environmental regulations and consumed as a result of the generation of electricity by utility owned generation plants" for recovery through the fuel

336 *Id.* at § 4.60j(9).
337 *Id.*
338 MINN. STAT. § 216B.16(7) (2023).
339 77-3 MISS. CODE. R. § 42(1)(b) (LexisNexis 2020).
340 *See id.* § 42(2)(a).

	adjustment clause.[341] This is similar to Illinois' provision.
Missouri	Has had FACs since 2007.[342] Rate adjustments can be used for both fuel expenses and "to recover costs related to environmental compliance."[343] However, "[t]he act stipulates a cap on this rate adjustment [because] any such adjustment shall not exceed two and one-half percent per year."[344] Costs recovered this way will be reviewed at least once every eighteen months.[345] The Commission allows (but does not require) "any party" to propose an incentive-aligning mechanism to ensure that utilities are prudent when incurring fuel costs.[346] It appears that all electric utilities in Missouri currently recover 95% of their costs, and incur 5% of the costs themselves.[347] Aside from FACs, Missouri's Utility Commission has allowed other rate adjustment clauses to be included in tariffs. For example, the renewable energy standard rate adjustment mechanism (RESRAM) is designed to recover costs associated with Missouri's Renewable Energy Standard and is included in Every's and Ameren's (the largest utilities) tariffs.[348] What is hard to comprehend is that RESRAM is meant "to reflect prudently

[341] MISS. PUB. SERV. COMM'N & PUB. UTILS. STAFF, PUBLIC UTILITIES RULES OF PRACTICE AND PROCEDURE 68 (2019).

[342] *See generally* S. 179, 93d Gen. Assemb. (Mo. 2006).

[343] *Id.*

[344] *Id.*

[345] *See generally id.*

[346] MO. CODE REGS. ANN. tit. 20, § 4240-20.090(14).

[347] *See, e.g.*, Democrat Staff, *PSC Approves Change to Evergy Fuel Adjustment Charge*, SEDALIA DEMOCRAT (Apr. 1, 2022), https://perma.cc/KQ2R-993G (explaining the 95% cap on company recovery); *Understanding Your Energy Statement*, AMEREN MO., https://perma.cc/JVR6-ELTT ("The FAC provides that 95% of the increases or decreases in actual net energy costs in between rate cases (net fuel and purchased power costs, and net off-system sales, including transportation) shall be passed through to customers.").

[348] *See PSC Approves Change in Evergy Missouri West RESRAM Charge*, MO. PUB. SERV. COMM'N (Nov. 16, 2023), https://perma.cc/LC3N-QMRN; *PSC Approves Change in Ameren Missouri RESRAM Charge*, MO. PUB. SERV. COMM'N (Dec. 8, 2022), https://perma.cc/FDD8-9Q82 [hereinafter *PSC Approves RESRAM Charge*].

	incurred renewable energy standard costs (such as solar and wind) . . . [and is] above renewable energy costs already included in the company's base rates."[349] Since there is little variable cost associated with renewable energy, it is not clear what costs are recovered here.
Montana	Montana has market-based rates and hence does not need a FAC. It does, however, allow for automatic rate adjustments based on changes in state and local tax rates, save for income taxes.[350]
Nebraska	I was unable to find information on Nebraska FACs.
Nevada	Nevada has both a FAC (called the Deferred Energy Accounting Adjustment) and a tax adjustment rider. The Deferred Energy Accounting Adjustment adjusts prices both up and down automatically, according to energy costs incurred by the utility.[351] The tax adjustment rider covers any "business license fee or gross receipts tax or similar tax" imposed by "any political subdivision."[352] Finally, Nevada also has an "Energy Efficiency Charge," established to "allow electric utilities to recover the program costs of energy efficiency and conservation programs, such as refrigerator recycling, pool pump and heating rebates, and discounts for LED light bulbs. Program costs include labor, overhead, materials, incentives paid to customers, advertising, marketing, monitoring and evaluation."[353]

[349] *PSC Approves RESRAM Charge*, *supra* note 348.

[350] MONT. CODE ANN. § 69-3-308 (2023) ("the commission shall allow a public utility to file rate schedules containing provisions for the automatic adjustment and tracking of Montana state and local taxes and fees, except state income tax, paid by the public utility.").

[351] *See* NEV. ENERGY, UNDERSTANDING YOUR BILL 2.

[352] SIERRA PAC. POWER. CO., SCHEDULE NO. TAR: TAX ADJUSTMENT RIDER (2004).

[353] NORTHERN NEVADA'S ELECTRIC RATES & CHARGES, PUCN, https://perma.cc/3DH4-2FVP. *See generally* S. 358, 75th Leg. (Nev. 2009).

New Hampshire	Has fuel adjustment clauses, but they do not apply automatically. Rather, utilities that generate their own power can levy fuel adjustment charges only after securing "approval from the [New Hampshire Public Utilities Commission] subsequent to a public hearing held at least 7 days prior to the first day of each month in which the charge is to be levied."[354] Utilities that simply purchase power and do not generate their own power may pass along fuel adjustment charges already approved by the Commission.[355]
New Jersey	New Jersey deregulated electricity in the 1990s, so rates are not set or approved by its public utility commission.[356]
New Mexico	Has both a fuel adjustment clause and a renewable energy rider. The former allows utilities to automatically adjust rates based on a commission-established formula, without the need for a hearing.[357] The commission can schedule a hearing if there is an unusual or substantial increase in cost, but this does not seem to happen much. A sample calculation formula can be found in the New Mexico Administrative Code.[358] The state also allows public utilities to recover costs of complying with its Energy Transition Act[359] (which sets a statewide renewable energy standard of 50% by 2030 and 80% by 2040).[360] Any costs, "including [a utility's] reasonable interconnection and transmission costs, costs to comply with electric industry reliability standards, and other costs attributable to acquisition and delivery of

354 N.H. REV. STAT. ANN. § 378:3-a(II) (1979).
355 *See id.* § 378:3-a(III).
356 The author is not aware of any requirement that rates be set or approved by New Jersey's public utility commission.
357 *See generally* N.M. CODE R. § 17.9.550 (2010).
358 *See id.* § 17.9.550.2.
359 N.M. STAT. ANN. §§ 62-18-1—62-18-23 (2019).
360 *See id.*

	renewable energy and zero carbon energy," are considered reasonable to recover through this rider.[361]
New York	Has fuel adjustment clauses that work automatically, but are to be reviewed no less than once per four years.[362] Utilities may also adjust rates in response to city and village utility revenue tax surcharges.[363]
North Carolina	Allows FACs without any particularly unique provisions.[364] North Carolina also allows utilities to charge a rider to recover costs associated with complying with the state's Renewable Energy and Energy Efficiency Portfolio Standard laws.[365] Utilities are allowed to fully recover all costs associated with renewable energy purchasing contracts, demand side management measures, and other costs related with compliance.[366] The utilities commission holds an annual hearing to review compliance costs, at which stakeholders may file comments and complaints.[367]
North Dakota	Allows FACs that automatically adjust rates without a commission hearing, so long as they are calculated using a commission-approved formula.[368] In addition, companies in North Dakota charge an "Environmental Cost Recovery Rider," meant to "recover jurisdictional capital costs and associated operating expenses incurred by a public utility to comply with federal environmental mandates on existing electricity generating stations," and a "Transmission Facility Cost Rider", meant to

361 N.M. ADMIN. CODE R. § 17.9.572.15(A) (2021).

362 *See* N.Y. COMP. CODES R. & REGS. tit. 16, §§ 720-6.1–720-6.3 (1999).

363 *See id.* § 720-6.8.

364 *See* N.C. GEN. STAT. § 62-133.2 (2014).

365 *See id.* at § 62-133.8.

366 *See* N.C. UTILS. COMM'N, R8-67 RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (REPS) at R8-67(e) (2008).

367 *See id.*

368 *See* N.D. ADMIN. CODE 69-09-02-39 (1995).

	"recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities."[369] Both of these riders must be approved by North Dakota Public Service Commission and are supposed to allow utilities to maintain their commission-approved return on investment.
Ohio	Energy has been deregulated in Ohio, and as a result, utilities have no say in the rates charged for energy.[370]
Oklahoma	Allows FACs that automatically adjust prices, but the clause has to be approved by Oklahoma's Public Utility Commission initially.[371]
Oregon	Has a FAC that automatically adjusts rates annually to "true-up" 90% of the costs incurred by utilities *outside of* the "deadband" of energy costs.[372] The negative annual power cost deadband is $15 million, and the positive annual power cost deadband is set at $30 million.[373] Note that there is both a deadband, meant to require the company "to absorb some normal variation of power costs," and a cost-sharing mechanism that gives utilities "an incentive to manage costs effectively" by having customers "bear 90 percent of the adjustment" and "[the utility] bear 10 percent of the adjustment."[374] Has an automatic cost recovery adjustment for environmental compliance costs incurred by a utility to remain in compliance with the Oregon Renewable Energy Act,[375] as well as

[369] N.D. CENT. CODE §§ 49-05-04.2, 49-05-04.3 (2007) .
[370] *See* OHIO REV. CODE ANN. § 4928.02 (West 2023).
[371] *See* OKLA. STAT. tit 17, § 251 (2022).
[372] *See generally* Portland Gen. Elec. Co., Schedule 126: Annual Power Cost Variance Mechanism (2022).
[373] *See generally id.*
[374] *In re:* Portland Gen. Elec. Co., Order No. 07-015, 26-27 (Pub. Util. Comm'n of Or. Oct. 1, 1997).
[375] S. 838 § 13, 74th Leg. (Or. 2007).

	for costs incurred in promoting energy-efficiency programs.[376]
Pennsylvania	Pennsylvania has deregulated its electric system, so rates get chosen and determined individually by providers.[377]
Rhode Island	Rhode Island has deregulated its electric system, so rates get chosen and determined individually by providers.[378]
South Carolina	Has FACs and defines fuel costs as both classic costs of fuel and transportation as well as "the cost of ammonia, lime, limestone, urea, dibasic acid and catalysts consumed in reducing or treating emissions, and . . . the cost of emission allowances, as used, including allowance for SO_2, NO_x, mercury, and particulates."[379] After a hearing, the utility may (upon Commission approval) "allow the variable costs of other environmental reagents, other environmental allowances or emissions-related taxes to be recovered as a component of fuel costs."[380] Hence, South Carolina utilities have little incentive to reduce emissions since they can pass along allowance costs to consumers. The South Carolina Public Service Commission requires that utilities make "every reasonable effort to minimize fuel costs."[381]
South Dakota	FACs must be approved in advance by the South Dakota Public Utilities Commission, but after that, adjustments may happen automatically.[382] South Dakota also allows for an annual "Transmission Cost Adjustment." These two adjustments are combined on

376 *See* OR. REV. STAT. § 757.054 (2021).
377 *See generally* 66 PA. CONS. STAT. § 28 (1997).
378 *See* 39 R.I. GEN. LAWS § 39-1-27 (1996).
379 S.C. CODE ANN. REGS. § 58-27-865(A)(1) (2022).
380 *Id.*
381 *Id.* § 865(F).
382 *See* S.D. ADMIN. R. § 20:10:13:100 (1986).

	customers' bills and show up as "Electric Cost Adjustments."[383]
Tennessee	Tennessee has FACs that are adjusted automatically each month based on commission-approved calculations.[384]
Texas	Allows FACs, but utilities must file petitions with the Texas Public Utility Commission before changing rates.[385] Utilities may also include a "Distribution Cost Recovery Factor" in their rates—this allows them to recover investments in "distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks."[386]
Utah	Has automatic FACs, although there does not appear to be explicit authorization for them in Utah's administrative code.[387]
Vermont	Generally does not allow FACs.[388]
Virginia	Has FACs that allow utilities to recover their *estimated* fuel costs. Utilities must file their estimated costs for the following year with the Virginia Public Utilities Commission, who then gets to approve it.[389] The charge is adjusted for any over- or under-recovery of fuel costs previously incurred, so eventually a "real" true-up does occur (although there is no penalty for overestimation of costs, i.e., no interest is collected on overcharges).[390]

383 *See generally, e.g.*, BLACK HILLS ENERGY, ELECTRIC COST ADJUSTMENT (2023).

384 *See Total Monthly Fuel Costs*, TENN. VALLEY AUTH., https://perma.cc/5WLJ-WHTV. Statutory authority for FACs is given to the Tennessee Public Utility Commission. *See* TENN. CODE ANN. § 65-5-103(5)(B) (2021) ("A utility may request and the commission may authorize a mechanism to allow for and permit a more timely adjustment of rates resulting from changes in essential, nondiscretionary expenses, such as fuel and power and chemical expenses.").

385 *See* 16 TEX. ADMIN. CODE § 25.236(b) (1999).

386 16 TEX. ADMIN. CODE § 25.243 (2011).

387 *See* EMPIRE ELEC. ASS'N, APPLICATION FOR POWER COST ADJUSTMENT CLAUSE (2012).

388 *See* VT. STAT. ANN. tit. 30, § 218d(n)–(o) (2021).

389 *See* VA. CODE ANN. § 56-249.6 (2021).

390 *See id.*

	In addition to fuel costs, Virginia utilities also charge “to recover the costs of clean energy and environmental programs.”[391] This is in fact required by law: “To the extent that a . . . Utility constructs or acquires new zero-carbon generating facilities or energy storage resources, the utility shall petition the Commission for the recovery of the costs of such facilities, at the utility’s election, either through its rates for generation and distribution services or through a rate adjustment clause.”[392] In general, Virginia allows utilities to petition for rate adjustments for a ton of reasons, not all of which make a lot of sense. For example, consider that “a utility may . . . petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of . . . a coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth,”[393] supposedly to promote reliability).
Washington	Allows for utilities to recover costs related to fuel, but requests must be filed with the Washington Utilities and Transportation Commission and must be approved by the Commission prior to coming into effect.[394] Utilities also adjust rates based on “municipal occupation, business, or excise taxes or charges.”[395]
West Virginia	Automatic fuel adjustment clauses are banned in West Virginia, and the language of West Virginia’s code seems to ban regular fuel adjustment clauses as well: “The

391 *See* DOMINION ENERGY, UNDERSTAND MY BILL (2023).
392 VA. CODE ANN. § 56-585.5(D) (2020).
393 VA. CODE ANN. § 56-585.1(A)(6) (2007) (other sections amended in 2023).
394 *See, e.g.*, Wash. Utils. and Transp. Comm’n, *Power Cost Adjustment Impacts New Puget Sound Energy Rates* (Jan. 12, 2023), https://perma.cc/T249-96A2.
395 *See* PAC. POWER, SCHEDULE 101: TAX ADJUSTMENT SCHEDULE 1 (2020).

	commission shall not enforce, originate, continue, establish, change or otherwise authorize or permit an increase in the charge or charges for electric energy over and above the established and published tariff, rate, joint rate, charge, toll or schedule through any automatic adjustment clause or fuel adjustment clause."[396] Yet utilities in West Virginia apply for cost recovery after incurring significant fuel expenditures. Earlier this year, the West Virginia Public Service Commission approved an $89 million rate increase for Appalachian Power for fuel costs (although Appalachian Power sought to recover $642 million).[397] It appears that this is because these discussions are simply classified as rate changes, rather than separate fuel cost adjustment clauses. West Virginia allows an "accelerated procedure" for rate changes in the case of changes in the cost of electricity.[398]
Wisconsin	Allows FACs. Utilities must file a proposed fuel cost with Wisconsin's Public Utility Commission annually, based on which the Commission adjust rates for the coming year.[399] In addition, utilities may also request to change their rates during the year, but only after a hearing.[400] According to the Wisconsin government, "[n]ew FAC rates are set on a forward-going basis. Therefore, utilities have a financial incentive to control their costs to produce or purchase energy, since they are only allowed to recover increased future costs (not costs already incurred)."[401] This seems a

396 W. VA. CODE R. § 24-2-15 (2020).

397 *See* Curtis Tate, *PSC Approves $89 Million Rate Increase for Appalachian Power*, W. VA PUB. BROAD. (Sept. 13, 2023), https://perma.cc/E8E9-5QDS.

398 *See* W. VA. CODE § 150-2-14 (2023).

399 *See* WIS. ADMIN. CODE PSC § 116 (2021).

400 *See* Wis. Pub. Serv. Comm'n, *Electric Residential Bill Comparisons: Definitions*, https://perma.cc/M2S3-ATP7.

401 *Id.*

	bit overly optimistic; utilities could simply overestimate projected fuel costs. Note also that fuel costs are defined to include "[r]enewable resource credits" and "[e]mission allowances, including allowances for sulfur dioxide and carbon dioxide."[402]
Wyoming	Allows FACs, which can operate automatically after the Wyoming Public Service Commission approves an application to do so. Also, interest is to be paid on over-collected balances.[403]

402 WIS. ADMIN. CODE PSC § 116.02(1)(g–h).
403 023-3 WYO. CODE. R. § 3-7 (LexisNexis 2016).