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Aneil Kovvali

Aneil.Kovvali@chicagounbound.edu

Joshua Macey

Joshua.Macey@chicagounbound.edu

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Hidden Value Transfers in Public Utilities

Aneil Kovvali* & Joshua C. Macey**

Many electric utilities in the United States own rate regulated and non-rate regulated subsidiaries. The rate regulated subsidiaries enjoy legal monopolies and a right to a return on their capital investments but are only allowed to charge regulatorily authorized rates. The non-rate regulated subsidiaries participate in competitive markets and are generally free to earn whatever profits they can but are subject to the threat of displacement by other enterprises.

This Essay describes some strategies vertically integrated electric utilities use to transfer value from rate regulated affiliates to non-rate regulated affiliates. First, regulated utilities directly subsidize non-regulated affiliates by entering into favorable contracts with affiliates that participate in competitive markets. These contractual value transfers include favorable purchase agreements such as long-term contracts to buy coal at above-market prices and cross-affiliate debt guarantees that allow non-rate regulated affiliates to borrow at a discount. Second, utilities receive regulatory authorization to pass costs incurred by their non-rate regulated affiliates onto captive ratepayers. Examples of regulatorily approved value transfers are fuel adjustment clauses that authorize recovery of fuel costs from captive ratepayers and self-insurance that forces ratepayers to bear wildfire risk and transmission outages (even when insurance requirements are supposed to protect them from those risks). Third, utilities make investment decisions in rate regulated markets that favor their non-rate regulated affiliates. For example, utilities may invest (or refuse to invest) in transmission capacity to protect the market power of their generation assets—not to reduce energy prices, improve grid reliability, or connect to low-carbon energy sources. Utility value transfers thus make the grid less efficient, less reliable, more difficult to supervise, and more resistant to policy instruments that should encourage decarbonization.

* Associate Professor of Law, Indiana University Maurer School of Law.

** Assistant Professor of Law, University of Chicago Law School. We thank Alison Gocke, Felix Mormann, Heather Payne, Ari Peskoe, Ganesh Sitaraman, Shelley Welton, and Hannah Wiseman for helpful comments and suggestions.

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Introduction

During his 1932 presidential campaign, Franklin Delano Roosevelt attacked electric and gas utilities for engaging in a “deliberate and unprincipled campaign of misinformation, of propaganda, and, if I may use the words, of lies and falsehood,”¹ for “influenc[ing] to the prejudice of the public the actions of public service commissions,”² and for “sell[ing] billions of dollars of securities which the public

¹ Governor Franklin D. Roosevelt, Campaign Address at Municipal Auditorium, Portland, Or. (Sept. 21, 1932), in Franklin D. Roosevelt--"The Great Communicator": The Master Speech Files, 1898, 1910-1945 4 (2008).

² Id. at 7.

have been falsely led into believing were properly supervised by the government itself.”³

One of Roosevelt’s chief concerns was that sprawling utility companies had used complex corporate structures to subsidize non-rate regulated affiliates and redistribute wealth from ratepayers to shareholders. Roosevelt charged that “sound subsidiaries had been milked and milked to keep alive the weaker sisters in the great chain. They [the public] did not realize that there had been borrowings and lendings--an interchange of assets, of liabilities and of capital between the component parts of the whole. They did not realize that all these conditions necessitated terrific overcharges for service(s) by these corporations.”⁴

As President, Roosevelt quickly turned his attention to energy regulation. A 1934 House Report described how gas and electric utilities evaded regulatory oversight and transferred value from ratepayers to shareholders.⁵ The report expressed concern that utilities were entering into favorable contracts with non-rate regulated affiliates, expanding into non-utility businesses,⁶ and using inter-company debt guarantees to further expose ratepayers to business risks without regulatory authorization.⁷ In response, Congress passed the Public Utility Holding

³ Id. at 14.

⁴ Id. at 18.

⁵ H.R. Rep. 73-827, pt. 3, at 27 (1934).

⁶ See id. at 40 (“The American Water Works and Electric System consists of two major groups: (1) A group of waterworks companies; (2) a group of companies the principal business of which is the generation and distribution of electric power. This latter group, however, includes transportation by rail and bus, and certain miscellaneous activities such as are implied by the names of such companies as Esperanza Land Corporation, Ajax Farm Corporation, James Mills Orchard Corporation, American Construction & Securities Co., and others.”); see also id. at 43 (“The system renders a considerable variety of services: 49 companies are actively engaged in furnishing water, 21 furnish electric power and light, 13 furnish transportation service (8 railway and 5 bus), 2 distribute natural gas and one manufactured gas, 3 supply their communities with ice. One company is engaged in farming and one in horticulture. Sewage disposal, coal mining, toll bridges, steam heat, sale of electrical appliances are businesses represented by one or more companies. Besides these activities serving the public, 4 investment and 4 construction companies are maintained for service within the system. . . . In several cases one company is engaged in several different kinds of businesses.”).

⁷ Id. at 27 (“[F]unded debt . . . did not appear on the [balance sheet] because it is all owned by the subsidiaries. It would seem that the subsidiaries have to some extent provided the funds with which their own stocks were purchased.”); id. [“(T]he American Railways Co. has a large contingent liability through guarantee of the bonds issued by former subsidiaries, and is now in receivership because the interest on these bonds has defaulted.”]; id. at 106 (“From the nature of the subsidiary company balance sheets, it seems that the debt in most of these cases arose in

Company Act of 1935 (PUHCA),⁸ which required utilities to operate in contiguous geographic service territories, mandated robust disclosure to the Securities and Exchange Commission (SEC), and imposed operational limits on the types of business activities utilities engaged in.⁹

This Essay describes different strategies public utilities have adopted to once again transfer value from rate regulated affiliates to non-rate regulated affiliates. Forty years of utility mergers and acquisitions has led to a substantial reduction in the number of independent utilities that operate in the United States.¹⁰ This consolidation is partly due to the repeal of PUHCA, which allowed utilities to expand into new industries and serve to larger geographic service territories. But it is also due to regulatory decisions that have allowed utilities to pass some of their non-rate regulated affiliates' costs onto their captive customers.¹¹ We provide a taxonomy of three types of these value transfers. First, regulated utilities directly subsidize non-regulated affiliates by entering into favorable contracts with affiliates that participate in competitive markets.¹² These contractual value transfers include favorable purchase agreements such as long-term contracts to buy coal at above-market prices and cross-affiliate debt guarantees that allow non-rate regulated affiliates to borrow at a discount. Second, utilities receive regulatory authorization to pass costs incurred by their non-rate regulated affiliates onto captive ratepayers.¹³ Examples of regulatorily approved value transfers are fuel adjustment

connection with intra group borrowing. A large proportion of the companies in the general system report advances from affiliated companies. All the funded debt of companies named on the list was held by members of the system but that of Lexington Water & Power Co., Erie Lighting Co., Elmira Water, Light, & Railroad Co., The Lake Shore Gas Co., Broad River Power Co., Pennsylvania Electric Co., and Metropolitan Edison Co. In all cases some of the debt was held within the system.”); *id.* at 179 (“This situation respecting the funded debt represents an extreme case of one type of group financing--on the credit on subsidiaries.”).

⁸ 15 U.S.C. § 79 et seq.

⁹ 15 U.S.C. § 79d; 15 U.S.C. § 79e(b); 15 U.S.C. § 79k.

¹⁰ See Scott Hempling, *Regulating Mergers and Acquisitions of U.S. Electric Utilities: Industry Concentration and Corporate Complication* xxiii (2020) (“Since, the mid-1980s, a stream of mergers and acquisitions has cut the number of local, independent electric retail utilities in the U.S. by more than half.”).

¹¹ For example, when the Federal Energy Regulatory Commission (FERC) required transmission utilities to provide independent power producers with open, nondiscriminatory access to transmission lines, it did not force transmission and retail utilities to sell their generation assets. As discussed in Part II, this has allowed vertically integrated utilities to enter into financing arrangements that expose captive ratepayers to financial risks undertaken by utilities' non-rate regulated affiliates.

¹² See *infra* Part II.

¹³ See *infra* Part III.

clauses that authorize recovery of fuel costs from captive ratepayers and self-insurance that forces ratepayers to bear the risk of wildfires and transmission outages. Third, utilities make investment decisions in rate regulated markets that favor their non-rate regulated affiliates.¹⁴ For example, a utility that owns both gas and electric utilities may resist electrifying business and residential buildings. Electrification would increase its electric utility's profits but reduce those of its gas utility (and possibly strand its gas assets). Similarly, utilities that manage the transmission system may be disinclined to build interregional lines because they want to prevent other resources from competing with their existing generation fleet.¹⁵

Cross-affiliate debt guarantees and other transfers from rate regulated affiliates to non-rate regulated affiliates distort energy markets in a variety of ways. First, ratepayer-backed subsidies lead to higher consumer costs by keeping uneconomic units online even after cheaper alternative have become available. Second, they can counteract state and federal regulations by allowing utilities to pass regulatory compliance costs onto captive ratepayers. And third, they reduce financial stakeholders' incentives and capacity to monitor corporate behavior. Creditors' incentives to supervise and exert control over business conduct are diminished when they can count on ratepayers to bail them out when the firms' investments fail. Even apart from reducing the efficiency of utility operations, these effects reduce the effectiveness of public policy tools and are slowing the transition to cleaner energy sources. By cushioning utility companies from the economic impacts of their decisions, these effects free utility companies to ignore or delay meeting urgent public needs.

Energy regulators have long worried that utilities would use their control over critical infrastructure to exercise market power in related markets. In response to this concern, William Baxter, who oversaw the breakup of AT&T as Deputy Attorney General in charge of the Department of Justice's Antitrust Division,

¹⁴ See *infra* Part IV.

¹⁵ This is especially problematic for wind and solar, which are typically located far away from load centers and therefore need a more robust transmission system to unlock their full economic and climate value. See The Nat'l Acads. of Scis., Eng'g, & Med., *The Future of Electric Power in the United States* 273 (2021)(recommending that FERC "require transmission companies and regional transmission organizations to analyze and plan for all of the following objectives: . . . economical opportunities to expand the interstate electric system to open up access to and development of renewable resources and to connect these regions with areas of high electricity demand."); Alexandra Klass, Joshua Macey, Hannah Wiseman, & Shelley Welton, *Grid Reliability Through Clean Energy*, 74 *Stan. L. Rev.* 969, 1022-28 (2022)(emphasizing the importance of an expanded and interconnected national transmission grid).

argued that rate regulated entities should be “quarantined.”¹⁶ FERC has repeatedly intervened to make sure independent power producers could connect to the transmission system. But neither FERC nor state regulators have seriously considered breaking up vertically integrated utilities in response to changing conditions and needs. The analysis below suggests that this is an error. Given the many ways utilities continue to abuse vertical integration, we argue that energy regulators should consider further market liberalization and force utilities to divest their non-regulated assets. Nothing short of full unbundling is likely to address the full range of hidden costs of vertical integration, including its distortive effects on markets and its tendency to mute economic forces that would otherwise drive the industry toward cleaner energy. Should these reforms prove politically infeasible, we recommend policies that would make utility value transfers more difficult.

This Essay proceeds in five Parts. Part I describes the regulatory structure of the electric power industry. Parts II, III, and IV describe different types of utility value transfers. Part V argues that regulators should mandate full corporate unbundling to address the problems created by these value transfers. It also discusses partial solutions that regulators can enact if they are unable or unwilling to order public utilities to divest themselves of non-rate regulated affiliates.

I. History and Background of Utility Regulation

Electricity production requires generation of electricity, transmission over long distances, and distribution to customers.¹⁷ For much of the twentieth century, all three segments of electricity production were regulated as public utilities.¹⁸

¹⁶ See Paul L. Joskow & Roger G. Noll, *The Bell Doctrine: Applications in Telecommunications, Electricity, and Other Network Industries*, 51 *Stan. L. Rev.* 1249, 1249-50 (1999) (“[Baxter’s theory] is that regulated monopolies have the incentive and opportunity to monopolize related markets in which their monopolized service is an input, and that the most effective solution to this problem is to ‘quarantine.’”). See generally Phillip Areeda, William F. Baxter, & Harry M. Reasoner, *Antitrust Policy*, in *American Economic Policy in the 1980s*, 573, 600-14 (Martin S. Feldstein ed., 1994).

¹⁷ Morgan Ricks, Ganesh Sitaraman, Shelley Welton & Lev Menand, *Networks, Platforms & Utilities: Law & Policy* 647 (2022).

¹⁸ The rate regulation model--as opposed to public ownership by municipalities--was first instituted in New York and Wisconsin in 1907. *Id.* at 654. It became the dominant model, and was largely unchallenged until restructuring took hold in the mid-1990s. See Severin Borenstein & James Bushnell, *The U.S. Electricity Industry After 20 Years of Restructuring*, 7 *Ann. Rev. Econ.* 437, 438 (“In the seven years between 1995 and 2002, a wave of major regulatory reform aimed at introducing

Utilities received exclusive franchises to sell electricity in geographically defined service areas. State public utility commissions (PUCs) authorized investment decisions and set the rates utilities could charge customers. Today, the transmission and distribution segments of electricity sales remain rate-regulated in much of the country,¹⁹ as does generation in the Pacific Northwest and Southeast.²⁰

Despite the enduring legacy of rate regulation, most of the country has restructured the generation segment of electricity production. Generators in restructured markets participate in competitive auctions that determine which generators are dispatched (sell electricity).²¹ These markets use a process called merit order (or economic) dispatch to select the resources that will operate in any given moment. Grid operators select generation resources in real time.²² In principle, the resources that submit the lowest-cost bids should be dispatched first. When demand increases, the grid operator dispatches the next cheapest resources--those that are more expensive than the ones that are already generating electric power but cheaper than every other available resource. The most expensive generator dispatched is called the price setter, because all resources that clear the market receive the price bid by that resource.

Since regulators began regulating the electricity industry as a public utility in the early twentieth century, they struggled to prevent utilities from using their rate regulated businesses to give themselves advantages in non-rate regulated markets. Rate regulated utilities have a strong incentive to transfer value to non-rate regulated affiliates. Regulators set the rates utilities can charge and closely

competition into various utility functions, known broadly as electricity restructuring, transformed the industry.”).

¹⁹ See Severin Borenstein & James Bushnell, *The US Electricity Industry After 20 Years of Restructuring*, 7 *Ann. Rev. Econ.* 437, 454, 460 (2015) (noting that transmission and distribution regulation has changed little since 2005).

²⁰ Even areas that have restructured generation have not abandoned that approach altogether in the generation side of the market. In MISO, for example, many generators continue to recover many of their costs through regulated rates charged by distribution affiliates even though those generators also participate in real-time energy markets. See Midcontinent Independent System Operator, Inc.’s Filing to Include a Minimum Capacity Obligation in the MISO Resource Adequacy Construct Docket No. ER22-____-000, at 5 (Nov. 30, 2021), https://cdn.misoenergy.org/2021-11-30_Minimum%20Capacity%20Obligation%20Filing608323.pdf [<https://perma.cc/BLA4-MAWQ>].

²¹ See Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 *U. Pa. L. Rev.* 1181, 1186 (2020) (explaining how “restructured” energy markets work).

²² Technically, there are day-ahead and real-time markets, and real-time markets settle in five-minute intervals. See Energy Markets, PJM, <https://learn.pjm.com/three-priorities/buying-and-selling-energy/energy-markets#:~:text=PJM's%20Day%2DAhead%20Market%20is,buyers%20and%20sellers%20of%20energy> [<https://perma.cc/D9MJ-988T>] (last visited June 6, 2023).

scrutinize their investment decisions. Rate regulated utilities therefore are low-risk investments that offer stable but unremarkable returns.²³ Shareholders that want to increase profits have to look outside the regulated business.

But the very stability that limits utilities' returns also creates opportunities for vertically integrated firms to pass business risks onto their ratepayers. This is one of the core problems energy regulators have sought to manage since they began regulating electric power companies in the early twentieth century.

By contrast, rates for non-rate regulated affiliates that operate in competitive markets are not set by regulators.²⁴ Opportunities to profit are therefore only limited only by what the market will bear. Firms may lose business if they raise prices. But that is why intercompany agreements are beneficial: if a non-rate regulated company finds a buyer that can pass costs onto ratepayers, it may be able to charge high prices without losing competition and protect itself from the risk that a downward shift in prices will reduce its own revenues.

These strategies encourage companies to get larger, become highly leveraged, and adopt opaque financial structures. More affiliates and financing arrangements create more opportunities to shift value, debts are needed to maintain control and hold the structure together, and complexity and opacity make it more difficult for regulators to police value transfers. Complexity, opacity, and excessive leverage are especially problematic when they prevent regulators and managers from fully understanding the financial risks that these structures create.

These dangers were realized during the Great Depression. By 1929, a wave of consolidation led by industry figures like Samuel Insull drove over 90% of the country's private electric output into the hands of just 16 holding company groups.²⁵ These corporate groups were staggeringly complex, to the point where it is unlikely that their own directors and officers fully understood them.²⁶ As disruption in the

²³ For an analysis of public utility incentives, see Aneil Kovvali & Joshua Macey, *The Corporate Governance of Public Utilities*, 40 *Yale J. on Regul.* 569 (2023).

²⁴ Technically this is not true in restructured electricity markets where regulators impose price caps to prevent market power abuses. See *Energy Offer Verification*, <https://www.pjm.com/markets-and-operations/energy/energy-offer-verification> [perma: <https://perma.cc/5ZTA-VD2L>]; *MISO Dashboard*, <https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/increase-the-energy-offer-cap/> [perma: <https://perma.cc/6N9K-9GP3>] (“As a precaution against possible market power, electric power markets have created caps for these energy offers.”).

²⁵ Roberta S. Karmel, *Is the Public Utility Holding Company Act a Model for Breaking Up the Banks that are Too-Big-To-Fail?*, 62 *Hastings L.J.* 821, 846 & n.160 (2011).

²⁶ *Id.* at 847 (“The public utility holding companies were complicated to a degree almost beyond comprehension.”); Taylor, *infra* note 30, at 188-90 (describing the Insull system as having five layers of companies and trusts, with cross-investments upwards, downwards, and sideways).

financial markets made it difficult to raise capital, these structures became unstable.²⁷ By 1932, key parts of Insull's empire collapsed into bankruptcy.²⁸ But even this process failed to shed light on these companies' financial entanglements. As an article in *Time* noted, "[t]he real value" of one reorganized company's "stock remained a blank mystery. Some subsidiaries were earning, some losing money. The job of drawing up a consolidated financial statement was described by its officers as 'nearly impossible.'"²⁹ The full losses to the public from the collapse of the Insull system would not be fully known until the 1940s.³⁰

Regulators responded by passing a series of energy laws in the mid-1930s designed to reduce leverage, simplify utilities' corporate structures, and require more transparent accounting practices.³¹ These included the Federal Power Act,

²⁷ E.g. Richard D. Cudahy & William D. Henderson, *From Insull to Enron: Corporate (Re)Regulation After the Rise and Fall of Two Energy Icons*, 26 *Energy L.J.* 35, 65-69 (2005) (describing the "collapse of the Insull Empire").

²⁸ E.g. Taylor, *infra* note 30 at 191 (describing collapse and attempting to compute eventual losses).

²⁹ *Business & Finance: After Insull*, *Time* (Aug. 31, 1936), <https://content.time.com/time/subscriber/article/0,33009,756588-1,00.html> [perma:perma.cc/4JCA-HVZT].

³⁰ Arthur R. Taylor, *Losses to the Public in The Insull Collapse: 1932-1946*, 36 *Bus. History Rev.* 188, 191 (1962) ("It was not until 1946, when the reorganization of companies had been completed and when the remaining claims of security holders had been adjusted, that a figure for the total loss to the public holders of Insull securities could be computed.").

³¹ New Deal reformers first responded by introducing new publicly owned enterprises to the power sector, including through the Tennessee Valley Authority and the Public Works Administration. See *Our History*, *Tenn. Valley Auth.*, <https://www.tva.com/about-tva/our-history> (last visited June 6, 2023). Public control was designed to discipline investor-owned utilities by showing that the threat of public ownership was real. See Shelley Welton, *Revamping Public Energy*, in *Politics, Policy and Public Options* 134, 140 & n.30 (Ganesh Sitaraman & Anne Alstott, eds. 2021); Franklin D. Roosevelt, *Campaign Address in Portland, Oregon on Public Utilities and Development of Hydro-Electric Power*, *Am. Presidency Project* (Sept. 21, 1932), <https://www.presidency.ucsb.edu/documents/campaign-address-portland-oregon-public-utilities-and-development-hydro-electric-power> ("[N]o community which is sure that it is now being served well and at reasonable rates by a private utility company, will seek to build or operate its own plant. But on the other hand, the very fact that a community can, by vote of the electorate, create a yardstick of its own, will, in most cases, guarantee good service and low rates to its population. I might call the right of the people to own and operate their own utility something like this: a 'birch rod in the cupboard to be taken out and used only when the child gets beyond the point where mere scolding does any good.'").

which gave the Federal Power Commission (now FERC) authority to regulate wholesale electricity sales,³² and the Public Utilities Holding Company Act (PUHCA), which prohibited the kinds of corporate governance and financial arrangements that had increased the costs borne by ratepayers when vertically integrated electric utilities became insolvent.³³

PUHCA empowered the Securities and Exchange Commission (SEC) to regulate and reform energy utilities.³⁴ All holding companies that owned an electric utility business or a gas distribution business were required to register with the SEC.³⁵ Holding companies could only operate within a single geographically integrated territory.³⁶ Nor could they retain an interest in non-utility businesses without SEC approval.³⁷ These rules were intended to allow the companies to capture the genuine operational synergies that came from managing related businesses within a specific geographic area while denying them unjustified opportunities for financial mischief.

After PUCHA was enacted, the energy industry settled into a structure dominated by investor-owned vertically integrated monopolies subject to rate regulation. Within a given geographic region, a single investor-owned utility could enjoy a monopoly over multiple steps in the process--generating electricity on a wholesale basis, transmitting it over long distances over high-voltage lines, transforming it to lower voltages, distributing it to end users, and retailing it to customers. That company was rate regulated and entitled to an opportunity to earn a reasonable return on its costs.

The model began to break down in the last quarter of the twentieth century as state and federal regulators sought to inject competition and increase innovation in the wholesale generation segment of electricity production.³⁸ Congress required vertically integrated utilities to connect with qualifying independent generators and to purchase their power at certain rates.³⁹ States, too, sometimes ordered utilities

³² 16 U.S.C. §§ 791–825r.

³³ Public Utilities Holding Company Act, Pub. L. 74-333, 74 Stat. 687 (1935), repealed by Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

³⁴ See Karmel, *supra* note 25, at 852-54 (summarizing key PUHCA provisions).

³⁵ 15 U.S.C. § 79d (PUHCA § 4).

³⁶ 15 U.S.C. § 79k(b)(1) (PUHCA § 11(b)(1)) (requiring actions found “necessary to limit the operations of the holding-company system of which such company is a part to a single integrated public-utility system”).

³⁷ *Id.* (limiting holding companies “to such other businesses as are deemed reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system”).

³⁸ Macey & Salovaara, *Rate Regulation Redux*, *supra* note 21, at 1200-03.

³⁹ *Id.* (discussing the implementation of the Public Utility Regulatory Policies Act of 1978 whereby vertically integrated utilities were required to allow “qualifying facilities”--renewable and cogeneration facilities--to connect to the grid and to purchase electricity from these qualifying facilities).

to divest themselves of their generation assets.⁴⁰ Often, these reforms built on power pools utilities had voluntarily created that allowed them to trade power to keep costs down and improve reliability.⁴¹

An essential part of the restructuring process was Order No. 888, which required transmission operators to make transmission capacity available to unaffiliated generators on nondiscriminatory terms.⁴² To do this, FERC encouraged utilities to participate in Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) (for convenience, we refer to both as RTOs).⁴³ RTOs are nonprofit entities that operate (but do not own) transmission facilities and oversee energy market auctions that determine which generators are dispatched.⁴⁴ Restructuring was meant to create a competitive market for generation by eliminating rate regulation for the generation side of electric production.

Over time, federal regulators became more accommodating of the sprawling corporate structures and financial arrangements that led Congress to pass PUHCA.

⁴⁰ See John Kwoka, Michael Pollitt & Sanem Sergici, *Divestiture Policy and Operating Efficiency in U.S. Electric Power Distribution*, 38 *J. Regul. Econ.* 86, 88-89 (2010) (noting that many states ordered or encouraged utilities to divest generation assets).

⁴¹ See PJM History, PJM, <https://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx> [<https://perma.cc/S6SH-GVFH>] (last visited Feb. 22, 2023). This all may suggest a clean line between wholesale generation and transmission and retail, which still generally happens within rate regulated utilities. The reality is far more complex, as many companies continue to own businesses on both sides of the fence. Indeed, the partial restructuring of energy markets has created new incentives for mischief. A pattern of industry consolidation since the 1980s has also concentrated ownership and expanded opportunities for cross-subsidization.

⁴² Order No. 888, *Federal Energy Guidelines: FERC Reports* (FERC), 75 FERC 61 (1996).

⁴³ Danny Cullenward & Shelley Welton, *The Quiet Undoing: How Regional Electricity Market Reforms Threaten State Clean Energy Goals*, 36 *Yale J. on Regul.* 106, 109 (2018).

⁴⁴ RTO mission creep and capture has been the subject of a large literature. See Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 *U. Pa. L. Rev.* 1181, 1236-55 (2020); Joshua C. Macey & Robert Ward, *MOPR Madness*, 42 *Energy L.J.* 67, 102-12 (2021); Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 *Cal. L. Rev.* 209, 230-35 (2021); Shelley Welton, *Electricity Markets and the Social Project of Decarbonization*, 118 *Colum. L. Rev.* 1067, 1104-22 (2018); Hannah J. Wiseman, *Regional Cooperative Federalism and the U.S. Electric Grid*, 90 *Geo. Wash. L. Rev.* 147, 151-52 (2022); Joel Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 *U.C. Davis L. Rev.* 1783, 1792-93 (2016); Joel Eisen & Felix Mormann, *Free Trade in Electric Power*, 2018 *Utah L. Rev.* 50, 57, 70.

By 1952, the SEC claimed that it had nearly completed the task of bringing the utility industry into compliance with PUHCA.⁴⁵ By the 1980s, the SEC was openly advocating for PUHCA's repeal.⁴⁶ The SEC got its wish when Congress repealed PUHCA in 2005.⁴⁷ As a result, utilities can once again operate in geographically discontinuous service territories, own non-utility businesses, and enter into inter-company financial arrangements that expose ratepayers to the risks undertaken by the companies' other subsidiaries.

FERC is aware that vertical integration creates opportunities for transmission operators and retail electric providers to wield market power in upstream and downstream markets, but it has not been particularly aggressive in policing this type of behavior. When FERC ordered transmission operators to provide nondiscriminatory, open access to their lines in Order No. 888, it declined to require utilities to sell their generation assets.⁴⁸ FERC's aim was "to remove impediments to competition in the wholesale bulk power marketplace."⁴⁹ It was concerned that utilities would use their control over transmission lines to prevent independent power producers from accessing markets and selling electric energy to consumers. But the Commission felt that it could prevent anticompetitive behavior by forcing utilities to separate transmission service from generation and requiring utilities to provide transmission service to themselves under the same terms and conditions they provided everyone else.⁵⁰ FERC has continued to implement reforms to increase competition in electric power markets and reduce utilities' market power, but it has never revisited its decision to allow utilities to remain vertically

⁴⁵ Securities and Exchange Commission, Eighteenth Annual Report of the Securities & Exchange Commission 82 (1952) ("It is now possible to state that the task of bringing about compliance with section 11 which had its real beginning in 1940 is rapidly nearing completion.").

⁴⁶ PUHCA's mandates were an uncomfortable philosophical fit for the agency, which normally focused on adequate disclosures to investors as opposed to deliberately channeling capital toward meritorious uses. Division of Investment Management, Securities and Exchange Commission, *The Regulation of Public-Utility Holding Companies* 6 (1995) ("The Holding Company Act, unlike other federal securities laws, requires not only disclosure but also SEC review of the merits of various transactions.").

⁴⁷ See Energy Policy Act of 2005, 42 U.S.C. §§ 16451-16463 (2005).

⁴⁸ Order No. 888, *Federal Energy Guidelines: FERC Reports*, 75 FERC 61, 59 (1996) ("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.").

⁴⁹ *Id.* at 1.

⁵⁰ *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 92 (Apr. 24, 1996) (codified at 18 C.F.R. Parts 35 and 385).

integrated.⁵¹ And while FERC is statutorily required to scrutinize utility mergers and debt financings,⁵² the Commission has not succeeded in preventing transactions that transfer value away from rate regulated utilities.⁵³

II. Contractual Value Transfers

The most direct way that utilities transfer value from ratepayers is through contracts between regulated and non-rate regulated affiliates that overcompensate the non-regulated affiliates. Contractual value transfers occur when utilities purchase supplies at above-market prices from non-rate regulated affiliates and when they guarantee the debt of non-rate regulated affiliates.

A. Favorable Contracts with Suppliers

Regulated utilities that have a financial stake in non-rate regulated firms can give themselves an above-market return by entering into favorable contracts with the non-regulated entity.

1. Contracts with Suppliers

PacifiCorp, a rate regulated utility that serves much of the Pacific Northwest (and a wholly owned subsidiary of Berkshire Hathaway), often purchases supplies from other subsidiaries of Berkshire Hathaway. Until approximately 2020, PacifiCorp had an ownership interest in ten coal plants in the western United States with 5,975 MW of operating capacity.⁵⁴ In some years, that amounted to nearly sixty percent of PacifiCorp's total generation capacity.⁵⁵ Berkshire Hathaway

⁵¹ Regional Transmission Organizations, Order No. 2000, 18 C.F.R. pt. 35 (1999); Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 18 C.F.R. pt 35 (2011).

⁵² 16 U.S.C. § 824; 18 C.F.R § 33.1; Federal Energy Regulatory Commission, Order No. 592, Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement 1-2 (1996).

⁵³ See *infra* Parts II-IV.

⁵⁴ See Energy Strategies, PacifiCorp Coal Unit Valuation Study 6 (2018).

⁵⁵ *Id.*

also owns the Burlington Northern Santa Fe Railway Company (BNSF),⁵⁶ which receives a large percentage of its revenue from transporting coal.⁵⁷

PacifiCorp's reliance on coal stood out compared to other utilities in the region. Throughout the 2010s, other utilities retired thousands of MW of coal-fired generators once other sources of energy became cheaper than coal.⁵⁸ PacifiCorp, by

⁵⁶ See Nick Zieminski, *Buffett buying Burlington rail in his biggest deal*, Reuters (Nov. 3, 2009), <https://www.reuters.com/article/us-burlingtonnorthern-berkshire-idUSTRE5A22A720091103>

⁵⁷ See Berkshire Hathaway, *Annual Report (Form 10-K)(2022)* at K-7, <https://www.berkshirehathaway.com/2022ar/2022ar.pdf> (for the year ending December 31, 2022, 16% of freight revenues were derived from coal); *id.* at K-27 (“BNSF derives significant amounts of revenue from the transportation of energy-related commodities, particularly coal.”); Tyler Godwin & Richard Rubin, *BNSF Q4 coal revenues, volumes decline on lower electricity demand*, S&P Global (Mar. 1, 2021), <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/030121-bnsf-q4-coal-revenues-volumes-decline-on-lower-electricity-demand>.

Although the relationship between PacifiCorp and BNSF has been subject to some oversight by state regulators, it is often difficult for the public to have confidence in the outcomes, as many key details are shielded from scrutiny under confidentiality arrangements and are not subject to meaningful checks by a competitive market. See *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of an Affiliated Interest Transaction with BNSF Railway Company*, Public Utility Comm'n of Ore. at 3 (May 8, 2018), <https://apps.puc.state.or.us/orders/2018ords/18-158.pdf> (“In this circumstance both a determination of market price and of cost based pricing is difficult. . . . PacifiCorp was unable to provide BNSF's cost when asked in an information request.”). Other companies in Berkshire Hathaway's portfolio have similar arrangements. See Form 10-K, Berkshire Hathaway 169 (2022), <https://www.sec.gov/ix?doc=/Archives/edgar/data/71180/000108131623000005/bhe-20221231.htm> (“MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company (“BNSF”), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2022, 2021 and 2020, \$100 million, \$76 million and \$90 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF agreement.”).

⁵⁸ Energy Strategies, *supra* at 5-6 (“Since 2010, more than 4,582 MW of coal-fired generation in the Western U.S. interconnection have been retired. Over the same period, 27,118 MW of wind and solar have been added to the region's generation portfolio. Looking forward, an additional 7,789 MW of coal-fired generation will likely be retired in the West by 2030. Despite these market developments, coal remains a significant fuel in PacifiCorp's power mix.”)

contrast, has proven reluctant to retire its coal-fired power stations and agreed to do so only in part because many of the states it serves banned coal.⁵⁹

PacifiCorp's contracts with its coal suppliers, which were also owned by Berkshire Hathaway, increased the company's financial interest in keeping its rate regulated coal-fired power plants online.⁶⁰ PacifiCorp's rate regulated businesses have limited opportunities to increase profits. It is difficult for the company to earn a return above that authorized by state public utility commissions. PacifiCorp's non-rate regulated affiliates, however, do not face those same constraints. Regulators do not cap their profits. If non-rate regulated affiliates can sell to regulated affiliates at above-market prices, and if those higher prices are borne by ratepayers instead of the regulated affiliate,⁶¹ they can increase their profits above the cap regulators imposed on the regulated utility. And if cheaper suppliers become available, inter-affiliate supply contracts can protect the non-rate regulated affiliate when market conditions become less favorable.

PacifiCorp's contracts with its coal mining affiliates appear to have allowed those mines to continue to operate even after gas became cheaper than coal. Many of PacifiCorp's coal-fired generators purchased coal from affiliates that were also

⁵⁹ See Ted Sickinger, *New PacifiCorp plan slows coal plant closures, adds lots of wind and solar*, *The Oregonian* (Oct. 3, 2019), <https://www.oregonlive.com/business/2019/10/new-pacificorp-plan-slows-coal-plant-closures-adds-lots-of-wind-and-solar.html> [perma.cc/3QLU-6SUV] (discussing the in PacifiCorp's six-state territory two states, Oregon and Washington, passed renewable energy transition laws that will prohibit utilities from using coal plants in the future).

⁶⁰ Even if PacifiCorp's parent company did not own many of its coal suppliers, PacifiCorp might have wanted to keep its coal-fired power plants online. PacifiCorp earns a return on investments regulators deem to be prudent. It takes a loss when regulators determine that certain investments were not prudently incurred. If PacifiCorp agrees to retire its coal-fired power plants early, it runs the risk that the regulator will not allow the company to recover (or earn a return on) the undepreciated portion of its investment in those plants. See *In the Matter of the Application of Rocky Mountain Power for Approval of the Transaction to Close the Deer Creek Mine and for a Deferred Accounting Order*, Case No. PAC-E-14-10, at 14 <https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE1410/CaseFiles/20141215Application.pdf> [perma.cc/7MXY-YR6Q] (requesting \$86 million for unrecovered investment). The rate regulated utility thus has a financial incentive to keep operating its existing assets--even after cheaper alternatives become available--because it may be forced to take a loss if it retires its existing assets early. And by capping its return on equity (ROE), regulators limit the financial incentive to invest in cheaper alternatives.

⁶¹ See *infra* Part III.A. (discussing how this cost-shifting works for fuel adjustment clauses).

owned by PacifiCorp.⁶² In a competitive market, both PacifiCorp's coal-fired power plants and its coal mines would have been unable to operate once cheaper alternatives became available.⁶³ The cheaper suppliers and generators would have taken market share from PacifiCorp as retail electric providers turned to those less expensive options.⁶⁴ PacifiCorp would have had to find a way to reduce its costs; its coal-fired power plants would have operated less frequently or retired if they could not cover their own costs. Similarly, a railroad that receives a large percentage of its revenue from transporting coal is highly exposed to the coal industry and would therefore expect to be financially harmed when the coal industry declines. However, because public utility commissions set PacifiCorp's returns, it is difficult for the company to lose market share to competitors.⁶⁵ Because PacifiCorp is likely

⁶² This occurred until state public utility commissions, perhaps in response to advocacy by the Sierra Club, ordered PacifiCorp to transition to cheaper and cleaner sources of power and retire part of its coal fleet. PacifiCorp does not plan to retire its coal fleet until the late 2030s at the earliest. See 2021 Integrated Resource Plan, PacifiCorp, at 15,

<https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf>

[<https://perma.cc/P8R2-VBSU>]. Under pressure from regulators, PacifiCorp has agreed to partial conversion of the Jim Bridger plant to natural gas. Brendan Lachance, Wyoming governor brokers deal to keep Jim Bridger Unit 2 open; carbon capture may be added at power plant, *Oil City News* (Feb. 17, 2022),

<https://oilcity.news/community/energy-community/2022/02/17/wyoming-governor-brokers-deal-to-keep-jim-bridger-unit-2-open-carbon-capture-may-be-added-at-power-plant/> [perma.cc/B7NL-Z6C8].

⁶³ Cf. Robert H. Scarborough III, Note, *Captive Coal Pricing and the Regulation of Utility-Affiliate Transactions*, 68 *Va. L. Rev.* 1409, 1434 (1982) (noting that mispricing of coal in affiliate transactions may create incentives to run inefficiently).

⁶⁴ It is less clear that this will happen in electricity markets, where buyers often have market power, can pass many of their costs onto ratepayers, and may engage in strategic behavior to take advantage of their market power. For an analysis of one type of buyer side market power abuse, see Joshua C. Macey and Robert Ward, *MOPR Madness*, *Energy L. J.* 67, 77-82 (2020).

⁶⁵ This effect can be exacerbated by fuel adjustment clauses, discussed *infra* Part III.A, which allow a rate regulated utility to pass the supra-competitive cost of coal produced by its affiliate to ratepayers. See Marshall A. Leaffer, *Automatic Fuel Adjustment Clauses: Time for a Hearing*, 30 *Case Western Res. L. Rev.* 228, 234 (1980) (“[W]hen the utility buys its fuel from a subsidiary or affiliated supplier . . . the utility may readily earn its supra-competitive profits by buying fuel from the nonregulated subsidiary at artificially high prices and then passing on these prices to the consumer through the [Fuel Adjustment Clause]”). While PacifiCorp is a rate regulated utility and has a monopoly over transmission and distribution, it does not

concerned that PUCs will not allow it to recover the value of unused coal, it has an incentive to tell PUCs that the coal-fired units are needed and to refuse to retire them until ordered to do so. While PacifiCorp's generators are rate regulated, its coal mines and railroads are not; no regulator caps their revenues. They can therefore earn extremely high profits if they can find a buyer willing to pay high prices.

In PacifiCorp's case, favorable long-term contracts between its rate regulated utilities and its coal mines appear to have allowed its coal mines to operate after the market had become less favorable for coal. For example, the Jim Bridger steam plant, which is a coal-fired power station and part of PacifiCorp's rate regulated electricity portfolio,⁶⁶ purchases coal from the Jim Bridger coal mine, which is also partially owned by PacifiCorp.⁶⁷ The Jim Bridger Power Station is one of the country's dirtiest power plants and has a long record of environmental infractions.⁶⁸ It is also one of PacifiCorp's most expensive units.⁶⁹ Despite these challenges, the

have a monopoly over generation in the Pacific Northwest. In fact, PacifiCorp recently announced that it plans to participate in a day-ahead energy market that will cover much of the West Coast. See PacifiCorp to Build on Success of Real-Time Energy Market Innovation As First To Sign on to New Western Day-Ahead Market, PacifiCorp (Dec. 8, 2022), <https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html> [<https://perma.cc/7MXL-8V78>]. Still, because the company recovers its generators' costs through regulated rates, the risks it faces from competition from other generators is limited.

⁶⁶ See PacifiCorp Coal Unit Valuation Study, Energy Strategies, at 6 <https://www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf> [perma.cc/4DLP-5PHC]

("Jim Bridger and Cholla were the highest cost units to operate among the Company's coal fleet, with costs ranging between \$37 and \$43 per MWh.").

⁶⁷ See The Application of PacifiCorp (U901E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue, (California Pub. Utils. Comm'n Nov. 3, 2022) (proposed decision approving PacifiCorp's 2022 energy cost adjustment clause rates), at 10 <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M498/K147/498147179.PDF> [perma.cc/G6PM-NE9V] ("Jim Bridger plant is currently served by two fuel sources: 1) coal secured through a coal supply agreement with third-party owned Black Butte mine, and 2) coal provided by the Bridger Coal Company (BCC) mine, which is a jointly-owned affiliate mine of PacifiCorp and Idaho Power.").

⁶⁸ America's Dirtiest Power Plants, Environment America Research & Policy Center, <https://publicinterestnetwork.org/wp-content/uploads/2022/05/AME-Americas-Dirtiest-Power-Plants-Factsheet.pdf> [<https://perma.cc/Z774-KZVR>] (listing Jim Bridger as the country's ninth dirtiest power plant, emitting the equivalent of 2,418,008 passenger vehicles a year).

⁶⁹ Aina Tan, A Look at Coal-Fired Capacity Idaho Power Plans To Retire, S&P Global (July 28, 2017), <https://www.spglobal.com/marketintelligence/en/news->

Jim Bridger Power Station continues to operate⁷⁰ as part of a portfolio of assets that is authorized to earn approximately 9.5% ROE on the portfolio of assets that includes the power plant.⁷¹

It is difficult to know whether the Jim Bridger Coal Mine has low costs, since the contracts between Jim Bridger Power Station and the Coal Mine are not publicly available, but there is evidence that the Jim Bridger Power Station has entered into favorable contracts with its suppliers. For the past five years, Jim Bridger Power Station has paid Black Butte, the other coal mine that sells coal to the Jim Bridger Power Station, approximately \$45 per short ton of coal.⁷² That is significantly higher than the average annual price coal-fired power plants have paid for coal, which has been approximately \$37 per short ton since 2012.⁷³ While it is possible that Jim Bridger pays a higher price for coal from Black Butte than it does

insights/trending/bnkit46vij0igs90vl4lmw2 [<https://perma.cc/E4E7-LFCB>] (“Jim Bridger reported costs at \$39.92/MWh in 2016. . .”).

⁷⁰ See *id.* (discussing the plan to retire the two Jim Bridger units in 2028 and 2032); 2021 Integrated Resource Plan, *supra* note 62, at 15 (Sept. 1, 2021)

<https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf>

[<https://perma.cc/P8R2-VBSU>] (describing options to retire Jim Bridger units or convert them to combined-cycle gas plants).

⁷¹ See 2019 PacifiCorp General Rate Case Information Sheet, Attorney General of Washington, at 1, https://agportal-s3bucket.s3.amazonaws.com/uploadedfiles/Home/Safeguarding_Consumers/Public_Counsel/2019-Pac-Information-Sheet_final_v3.pdf [perma.cc/7BD5-NEVV] (“[T]he ROE will remain at the current 9.5% through January 1, 2024”); In the Matter of Idaho Power Company’s Application for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the Jim Bridger Power Plant (May 13, 2022), at 16

<https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2117/Company/20220513Reply%20Comments.pdf> [perma.cc/XZB4-3SKB] (“[T]he Company voluntarily proposed to use a 9.5 percent ROE, less than the authorized ROE included in base rates, in the quantification of the Bridger coal-related levelized revenue requirement to reflect the balancing account methodology that provides for full recovery of the ROE for Bridger. The Commission ultimately approved this reduced return. . .”).

⁷² See Coal Shipment Price: Black Butte and Leucite Hills to Jim Bridger: Subbituminous Quarterly, U.S. Energy Info. Admin., https://www.eia.gov/opendata/v1/qb.php?category=773540&sdid=COAL.SHIPMENT_PRICE.4801180-8066-SUB.Q [perma.cc/5NYD-JVVV].

⁷³ See Coal Prices and Outlook, U.S. Energy Info. Admin., <https://www.eia.gov/energyexplained/coal/prices-and-outlook.php> [perma.cc/9JAT-EXD2].

for coal from the Jim Bridger coal mine,⁷⁴ the fact that state public utility commissions have allowed it to pay a premium to an unaffiliated supplier, and the fact that electricity produced by Jim Bridger is relatively expensive compared to PacifiCorp's other coal-fired power plants,⁷⁵ at least suggests it may have been allowed similarly favorable contracts between the Jim Bridger Power Station and the Jim Bridger Coal Mine. Regardless of the specific terms of the contract between Jim Bridger Power Station and Jim Bridger Coal Mine, coal has been more expensive than other energy sources for most of the past decade. Thus, the fact that the Jim Bridger Power Station has remained part of a portfolio of assets that earn a healthy return not only means that the power plant likely operated after it was no longer economic, but also that it supported a coal mine that would have struggled to stay in business without a long-term contract to supply a utility that was able to pass the costs of its contract onto captive ratepayers.⁷⁶

⁷⁴ One possible piece of supporting evidence is that PacifiCorp appears to have paid \$148 million to Bridger Coal and Trapper Mining Inc. services for coal. Berkshire Hathaway Energy Co., Annual Report (Form 10-K)(2021), at 250, https://www.brkenegy.com/assets/upload/financial-filing/20211231_PAC%20Form%2010-K.pdf. Bridger Coal previously supplied approximately 4 million short tons of coal per year. Andrew Graham, Jim Bridger: Lighting the country, laboring in the dark, WyoFile (Sept. 3, 2019), <https://wyofile.com/jim-bridger-lighting-the-country-laboring-in-the-dark/> [perma.cc/36GN-QNTX]. However, this figure has decreased since the decline and shutdown of the mine's underground operations. Cooper McKim, Wyoming's Only Underground Coal Mine Is Preparing To Close, Wyo. Pub. Radio (Sept. 21, 2021), <https://www.wyomingpublicmedia.org/natural-resources-energy/2021-09-21/wyomings-only-underground-coal-mine-is-preparing-to-close> [perma.cc/7SAQ-SCJT] (describing decline and shutdown of underground operations).

⁷⁵ See Energy Strategies, *supra* note 54, at 6 (describing Jim Bridger's costs as the highest costs amongst the company's fleet).

⁷⁶ For an analysis of the coal mining industry's financial struggles, see Joshua Macey & Jackson Salovaara, Bankruptcy as Bailout: Coal Company Insolvency and the Erosion of Federal Law, 71 *Stan. L. Rev.* 879, 906-27 (2019).

Jim Bridger is not the only example in which PacifiCorp has had a financial stake in companies that supplied its coal-fired assets.⁷⁷ The company has a long history of owning both sides of the supply chain, as do other utility companies.⁷⁸

2. Gas Precedent Agreements

A similar issue occurs when FERC relies on agreements between affiliates to evaluate whether a proposed interstate pipeline is warranted by market needs. A precedent agreement is an agreement between a shipper (a buyer) of gas and the pipeline. The shipper agrees to pay the pipeline for a firm transportation obligation.

When FERC approves new interstate pipelines, it is supposed to follow its 1999 policy statement on pipeline siting. There, FERC said that it would consider “all relevant factors,” including the environmental impact, expected future demand, and potential alternative suppliers.⁷⁹ In reality, FERC has approved pipelines whenever the pipeline found a buyer.⁸⁰ When FERC reviews proposals for new gas

⁷⁷ Although PacifiCorp has pared back its portfolio, it previously owned stakes in the Centralia Power Plant and nearby Centralia Coal Mine. See Bloomberg News, *Canadian Utility To Buy U.S. Power Plant*, N.Y. Times (May 11, 1999), <https://www.nytimes.com/1999/05/11/business/canadian-utility-to-buy-us-power-plant.html> [perma.cc/3VSN-XZER]. PacifiCorp also previously operated the Deer Creek mine in Utah. Steve Law, *PacifiCorp Closing Coal Mine*, Portland Tribune (Dec. 19, 2014), https://www.portlandtribune.com/archives/sustainable_life/pacificorp-closing-coal-mine/article_18c9490d-83a5-58f4-bce5-2b4d6084a26b.html [perma.cc/G2CC-F7C5]. PacifiCorp also spun off a set of mining interests into a company called NERCO in 1977. See *PacifiCorp To Sell Resources Business for \$384 Million*, UPI (Feb. 18, 1993), <https://www.upi.com/Archives/1993/02/18/Pacificorp-to-sell-resources-business-for-384-million/1488730011600/> [perma.cc/QQG6-AJP2].

⁷⁸ For example, in 2014, after agreeing to sell some of its coal mines, Rocky Mountain Power, a rate regulated affiliate of Berkshire Hathaway, recovered costs it incurred operating and closing the coal mine by passing those costs onto its ratepayers. See *Berkshire Hathaway Energy Co., Annual Report (Form 10-K) (2015)*, <https://www.sec.gov/Archives/edgar/data/71180/000108131616000023/bhe123115form10-kcombined.htm> [perma.cc/E38K-2K28]. While Rocky Mountain Power’s electric utilities are rate regulated, its coal mines are not. They make money by selling coal to electricity generating affiliates.

⁷⁹ FERC, *Statement of Policy, Certification of New Interstate Natural Gas Pipeline Facilities*, Docket No. PL99-3-000 (Sept. 15, 1999), at 23.

⁸⁰ See Susan Tierney, *FERC’s Certification of New Interstate Natural Gas Facilities, Revising the 1999 Policy Statement for 21st Century Conditions*, Analysis Group (Nov. 2019), at 3, https://www.analysisgroup.com/globalassets/content/insights/publishing/revising_fe

pipelines, it determines whether there is a need for the project. If it makes such a finding, FERC grants the pipeline a certificate of public convenience and necessity, which allows the pipeline company to exercise eminent domain.⁸¹

Like PacifiCorp's contracts with affiliated coal suppliers, the use of precedent agreements gives rate regulated utilities opportunities to place the risks of capital investments on ratepayers while allowing shareholders to capture the upside of those investments. Consider the Spire Pipeline, which FERC approved because the pipeline had a precedent agreement with a shipper that agreed to purchase 87.5% of pipeline's firm transport capacity.⁸² In that case, the shipper was Spire's local distribution company, the rate regulated firm that purchases gas from pipelines to sell to end-users. Spire estimated that the pipeline would cost just over \$220 million.⁸³ Spire's distribution company would purchase the gas and pass those costs to its ratepayers, and it would do so even though demand in Saint Louis, the region that the pipeline would serve, was not expected to grow.⁸⁴

Spire justified the new pipeline by claiming that its other supply contracts were coming to an end, and it felt that the new pipeline would better serve its customers' gas needs.⁸⁵ It is difficult to evaluate this justification. The use of the precedent agreement obviated the need for a competitive solicitation, so there was

rc_1999_pipeline_certification.pdf [perma.cc/5JGF-JQS3] (stating that FERC uses precedent agreements as evidence of a project's need); Alison Gocke, Finding the Public Convenience and Necessity in the Natural Gas Act (Tentative Title), at 5 (explaining that FERC proceedings skew in favor of pipeline certification "so long as there [is] some indicia of market support for the pipeline in the form of a contract between two private parties."); Commissioner Richard Glick Dissent Regarding Spire STL Pipeline LLC, Docket No. CP17-040-002 (Nov. 21, 2019), https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-spire-stl-pipeline-llc#footnote6_c1n9c3c [perma.cc/6HCR-F5Z3] ("In recent years, however, the Commission has adopted an increasingly doctrinaire position that the mere existence of agreements between a pipeline developer and one or more shippers to contract for capacity on the proposed pipeline is sufficient, by itself, to demonstrate the need for the proposed pipeline.").

⁸¹ 15 U.S.C. § 717f(e).

⁸² FERC, Order Issuing Certificates, Docket Nos. CP1740-000, CP17-40-001 (Aug. 3, 2018), at 4. For a discussion of FERC's approval of the Spire STL Pipeline, see Gocke, *supra* note at 80, at 28-30.

⁸³ See Certificate Order, 164 FERC ¶ 61,085, at ¶ 9 (2018) ("Spire estimates that the cost of the proposed facilities will be approximately \$220,276,167.").

⁸⁴ See Spire STL Pipeline LLC, 169 FERC ¶ 61,134, at ¶ 23 (2019) (Rehearing Order) ("We recognize that the current load forecasts for the St. Louis market area are flat . . .").

⁸⁵ See Certificate Order, 164 FERC ¶ 61,085, at ¶ 11 (2018) (stating that Spire argues its pipeline will increase supply diversity, increase reliability, and reduce costs).

no market test to determine whether Spire was able to transport fuel to its distribution affiliates more economically than pipelines that were already selling firm capacity to Spire. It is possible that Spire's pipeline was the least expensive way to meet its customers' need for firm gas capacity, but it is at least plausible that Spire entered into the precedent agreement so that its pipeline affiliate could make a large capital investment, recover that investment from its ratepayers, and push a competitor out of the market. Enable MRT, the company that owned one of the pipelines that had previously been supplying Spire's customers, alleged that Spire was building the pipeline for precisely that reason.⁸⁶

The Spire pipeline has been tangled in litigation, and its eventual fate is uncertain.⁸⁷ But Spire is a fairly typical example of the process by which pipelines receive certificates to build new gas pipelines.⁸⁸ Between 1999 and 2019, FERC granted 474 certificates authorizing new gas pipelines.⁸⁹ Of these, all but two were based on precedent agreements, usually between affiliated companies.⁹⁰ Thus, most pipelines that are being constructed today received regulatory authorization because they had an existing contract to sell pipeline capacity, and many are simply selling to themselves. Moreover, because the costs gas distribution companies incur to pay for pipeline capacity are passed onto ratepayers, a utility like Spire that self-supplies can lock in gas and reduce the need for renewables.

⁸⁶ See *Env't Def. Fund v. FERC*, 2 F.4th 953, 963-64 (D.C. Cir. 2021) (recounting arguments in Enable MRT's protest).

⁸⁷ The U.S. Court of Appeals for the D.C. Circuit held that the FERC approval "was arbitrary and capricious" because of its reliance on a single precedent agreement with an affiliated shipper. See *Environmental Defense Fund v. FERC*, 2 F.4th 953, 976 (D.C. Cir. 2021). FERC issued a new approval in December 2022. See Order on Remand and Reissuing Certificates, *Spire STL Pipeline LLC*, Dkt. No. CP17-40-006, 181 FERC ¶ 61,232, 2022 WL 17731035 (Dec. 15, 2022); Daniel Moore, *Spire Gas Pipeline Backed by Regulator After Court Rejection*, Bloomberg Law (Dec. 15, 2022), <https://news.bloomberglaw.com/environment-and-energy/spire-gas-pipeline-backed-by-top-regulator-after-court-rejection> [<https://perma.cc/PD4P-K9B6>].

⁸⁸ See Gocke, *supra* note 80, at 30 (presenting evidence "that the Spire Pipeline project is not an outlier in FERC's certificate applications").

⁸⁹ Alexandra B. Klass, *Evaluating Project Need for Natural Gas Pipelines in an Age of Climate Change: A Spotlight on FERC and the Courts*, 39 *Yale J. on Regul.* 658, 667 (2022).

⁹⁰ *Id.* at 665-67; *Approved Major Pipeline Projects (1997-Present)*, FERC, <https://ferc.gov/industries-data/natural-gas/approved-major-pipeline-projects-1997-present> [perma.cc/2HZG-F3EF] (last visited Mar. 12 2023); Emily Pitlick Mallen & Katy Lukaszewski, *Pipeline Outlook: How FERC Reliance on Precedent Agreements Could Change*, Law.com (Mar. 1, 2018), <https://www.law.com/texaslawyer/2018/03/01/pipeline-outlook-how-ferc-reliance-on-precedent-agreements-could-change/> [perma.cc/GDU8-H2FY].

In doing so, pipelines also manage to evade regulatory scrutiny. When reviewing interstate pipeline proposals, FERC is supposed to determine that the pipeline “is or will be required by the present or future public convenience and necessity.”⁹¹ Yet by granting pipeline certificates whenever the pipeline has a contract with a rate regulated affiliate, FERC effectively outsourced the decision about whether to authorize a new pipeline to the gas company that wants to build the new line. And because that company is able to pass its costs onto captive ratepayers, regulators cannot rely on the market to force the utility to make prudent and cost-effective investments. While new guidelines suggest that FERC may be prepared to address this problem,⁹² it remains to be seen whether it will take a noticeably different approach.

B. Cross-Affiliate Debt Guarantees

Another way that utilities transfer value from ratepayers to shareholders is through cross-affiliate debt guarantees. When regulated utilities guarantee the debt of non-rate regulated affiliates, they expose ratepayers to the risks undertaken by non-rate regulated affiliates and give those affiliates an advantage over their competitors.

In restructured markets, energy auctions are supposed to make sure that customers’ energy needs are being met at the lowest possible cost.⁹³ Rate regulated utilities that guarantee the debt of their non-rate regulated affiliates distort this process. If a subsidiary that sells energy in wholesale markets is unable to meet its debt obligations, its creditors will be able to recover from the rate regulated affiliate. By reducing non-rate regulated affiliates’ capital costs, cross-affiliate debt guarantees increased generators’ profits. If the energy market provides \$1 billion a

⁹¹ Natural Gas Act § 7, 15 U.S.C. § 717f.

⁹² In 2018, FERC issued a notice of inquiry indicating that it was considering revisions to its 1999 policy statement. Certification of New Interstate Natural Gas Facilities, FERC, 83 FR 18020-01, Dkt. No. PL18-1-000 ¶ 54 (Apr. 25, 2018) (“recent changes in the gas industry, whereby producers are contracting for an increasing amount of transportation capacity as well as an increase in the number of shippers that are affiliated with the pipeline companies, have raised questions among some entities as to whether pipeline agreements remain an appropriate indicator of need”). FERC reiterated its interest in the issue in 2021. Certification of New Interstate Natural Gas Facilities, FERC 86 FR 11268-02 (Feb. 24, 2021). FERC ultimately issued updated policy guidance pledging to “look[] at evidence beyond precedent agreements,” including “circumstances surrounding the precedent agreements” and “other evidence of need.” Certification of New Interstate Natural Gas Facilities, FERC 87 FR 11548-01 ¶ 54 (Mar. 1, 2022).

⁹³ See *supra* notes 21-22 and accompanying text.

year to a 500 MW power plant, and the plant would incur \$950 million in costs without a debt guarantee, it would make \$50 million in profit. If the debt guarantee reduces the plant's cost to \$925 million, it would now make \$75 million.⁹⁴

Since utilities' 10-Ks typically list debt guarantees at the parent level,⁹⁵ it is difficult to know if all the debt guarantees utilities disclose in their 10-Ks expose

⁹⁴ We assume the plant is not a price setter and that the debt guarantee does not affect the market clearing price.

⁹⁵ Utilities and other public companies are only required to disclose material risks. Some inter-company debt guarantees, such as Duke and Dominion's multi-billion guarantee of the Atlantic Coast Pipeline's debt, are material and therefore disclosed. See Duke Energy Corp., Annual Report (Form 10-K) (2021), at 179 ("In October 2017, ACP executed a \$3.4 billion revolving credit facility with a stated maturity date of October 2021. Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. In July 2020, ACP reduced the size of the credit facility to \$1.9 billion. Duke Energy's maximum exposure to loss under the terms of the guarantee is \$860 million as of December 31, 2020."); see Duke Energy Corp., Annual Report (Form 10-K) (2022), at 150 ("In February 2021, Duke Energy paid approximately \$855 million to fund ACP's outstanding debt, relieving Duke Energy of its guarantee."). In many cases, companies only disclose debt guarantees of the parent and acknowledge that subsidiaries may have similar arrangements. See, e.g., Berkshire Hathaway Energy Co., Annual Report (Form 10-K) (2021), at 109 ("It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof."); AEP, Annual Report (Form 10-K) (2021), at 282 ("AEP has \$4 billion and \$1 billion revolving credit facilities due in March 2026 and 2023, respectively, under which up to \$1.2 billion may be issued as letters of credit on behalf of subsidiaries."); Duke Energy Corp., 2021 Annual Report and Form 10-K, at 154 (2021), <https://desitecore10prod.cd.azureedge.net/annual-report/-/media/pdfs/our-company/investors/de-annual-reports/2021/2021-duke-energy-annual-report.pdf?rev=f3700925e6134fc6a138ad691d82a6e9> [<https://perma.cc/XQ38-QT8K>] (Duke Energy uses bank-issued standby letters of credit to secure the performance of wholly owned and non-wholly owned entities to a third party or customer. Under these arrangements, Duke Energy has payment obligations to the issuing bank that are triggered by a draw by the third party or customer due to the failure of the wholly owned or non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2021, Duke Energy had issued a total of \$586 million in letters of credit, which expire between 2022 and 2023. The unused amount under these letters of credit was \$54 million."); Dominion Energy, Inc., Annual Report (Form 10-K), at 198 (Dec. 31, 2021)

ratepayers to risks incurred by non-rate regulated affiliates. It is possible that many involve only non-rate regulated affiliates. Even then, however, inter-company debt guarantees still expose ratepayers to risks undertaken by the non-rate regulated affiliate. If an affiliate is in danger of defaulting on its debt, the company has a financial incentive to transfer funds from its healthy subsidiaries to the parent. The parent can then transfer those funds to the financially distressed subsidiary, which decreases the likelihood that the distressed subsidiary will default. That has a similar effect as a direct debt guarantee between the rate regulated and non-rate regulated affiliate. Funds flow from one subsidiary to the parent to another subsidiary, since the funds generated by the rate regulated subsidiary are still being used to reduce a non-rate regulated subsidiary's credit risk. Alternatively, the parent could keep the revenue generated by the rate regulated subsidiary on its books. That will increase the parent's ability to honor its own obligation, again using revenue generated by the rate regulated subsidiary to lower the non-rate regulated affiliate's capital costs.

One effect of these financial arrangements is to increase the cost of debt for the rate regulated subsidiary. The cost of debt reflects the likelihood that the borrower will default.⁹⁶ A rate regulated subsidiary that transfers a large percentage of its revenue to its parent company will be at greater risk of default than one that keeps liquid assets on its books. Creditors will therefore charge higher interest rates. Thus, even when rate regulated affiliates do not directly guarantee the debt of non-rate regulated affiliates, parents that own rate regulated and non-rate regulated subsidiaries are still in a position to pass the risks of the non-rate regulated affiliates onto their regulated subsidiaries' ratepayers.

Moreover, there is evidence that rate regulated subsidiaries do directly guarantee debt incurred by non-rate regulated affiliates. Sometimes, inter-company debt guarantees are obviously material and must therefore be disclosed in utilities' 10-Ks. Duke and Dominion, for example, guaranteed a multi-billion-dollar credit

<https://d18rn0p25nwr6d.cloudfront.net/CIK-0000715957/7868f821-bbaa-44c0-aa93-185e3e4b0f7d.pdf> [<https://perma.cc/J9UT-NYQW>] (“Upon the closing of the GT&S Transaction, Dominion Energy retained its four guarantees related to Cove Point, an equity method investment, in support of terminal services, transportation and construction. Two of the Cove Point guarantees have a cumulative maximum exposure of \$1.9 billion while the other two guarantees have no maximum limit.”). Limited disclosure requirements can create another incentive for utility companies to grow larger, so that fewer arrangements cross the materiality threshold and must be reported. Cf. George S. Georgiev, *Too Big to Disclose: Firm Size and Materiality Blindspots in Securities Regulation*, 64 *UCLA L. Rev.* 604, 657 (2017) (noting that larger firms can shield more matters from disclosure because they are financially immaterial, distorting patterns of investment).

⁹⁶ See, e.g., William J. Carney, Robert P. Bartlett, III & George S. Geis, *Corporate Finance: Principles and Practice* 103-04 (4th ed. 2020).

facility for the Atlantic Coast Pipeline.⁹⁷ The pipeline was a joint venture between the two companies. After encountering opposition from landowners and environmental groups, the pipeline was canceled, causing hundreds of millions of dollars in payments to close out those debt guarantees.⁹⁸

Utility bankruptcy filings also show that utilities have used inter-company debt guarantees to expose their ratepayers to risks undertaken by their non-rate regulated affiliates.⁹⁹ FirstEnergy Solutions (FES) filed for bankruptcy in 2019. The parent corporation and some of its other subsidiaries did not file. FES had both wholesale and retail operations in two organized energy markets, PJM, which serves parts of the mid-Atlantic region, and MISO, which serves parts of the

⁹⁷ See *supra* note 95 (citing relevant Duke and Dominion disclosures).

⁹⁸ See Duke 2022 Annual Report, *supra* note 95, at 150 (“In February 2021, Duke Energy paid approximately \$855 million to fund ACP’s outstanding debt, relieving Duke Energy of its guarantee.”). Debt guarantees between pipelines and regulated utilities raise unique issues. Because FERC must find that there is demand for the pipeline before granting a certificate of public convenience and necessity, pipeline debt guarantees work like precedent agreements between affiliates. By reducing the cost of capital, debt guarantees to pipelines allow the pipeline to sell capacity at a lower cost than it otherwise would. That increases the likelihood that FERC will find that there is a market need for the pipeline, since it allows the pipeline to sell capacity at more competitive rates than it otherwise would. See *supra* Part I.A.ii (discussing FERC process for awarding certificates of public convenience and necessity).

⁹⁹ See Fitch Assigns First-Time Ratings to FirstEnergy Corp Subsidiaries, FitchRatings (Jan. 6, 2017, 3:33 PM), <https://www.fitchratings.com/research/corporate-finance/fitch-assigns-first-time-ratings-to-firstenergy-corp-subsidiaries-06-01-2017> [perma.cc/L2ST-7D9V] (“FE will provide a two-year \$700 million secured revolving credit and surety credit support facility to FES as borrower and FG and FN as guarantors.”); FirstEnergy Corp., Annual Report (Form 10-K) (2021), at 49 (2021), <https://d18rn0p25nwr6d.cloudfront.net/CIK-0001031296/28c28793-3253-4dcc-ad30-30d3c85ac2b9.pdf> [https://perma.cc/P64Q-AQV2] (“FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy and its subsidiaries could be required to make under these guarantees as of December 31, 2021, was approximately \$1.1 billion. . . .”); *id.* at 114 (“As of December 31, 2021, outstanding guarantees and other assurances aggregated approximately \$1.1 billion, consisting of parental guarantees on behalf of its consolidated subsidiaries (\$0.6 billion) and other assurances (\$0.5 billion).”).

Midwest and Manitoba.¹⁰⁰ FES thus operated generation units that sold energy in the wholesale market and retail electric providers that purchased energy in the wholesale market and passes their costs onto captive ratepayers.¹⁰¹ When FirstEnergy filed for bankruptcy, its disclosure revealed that the company had used rate regulated subsidiaries to guarantee wholesale market participants' debt. For example, FES had a \$150 million credit facility with Allegheny Energy Supply Company, another FirstEnergy Subsidiary. When FES filed for bankruptcy, Allegheny owed FES \$102 million.¹⁰² FES also guaranteed the debt of FG and NG, which were FES subsidiaries that owned its coal-fired power stations and nuclear reactors.¹⁰³ FES also guaranteed fixed-income securities issued by a coal-fired power plant. When it filed for bankruptcy, \$769 million of that power plant's principal was outstanding.¹⁰⁴ Other utilities have entered into similar intercompany financing arrangements.¹⁰⁵

¹⁰⁰ See Disclosure Statement for the Joint Plan of Reorganization of FirstEnergy Solutions Corp., et al., Pursuant to Chapter 11 of the Bankruptcy Code, at 38, In re FirstEnergy Solutions Corp., No. 18-50757 (Bankr. N.D. Ohio Feb. 11, 2019), Doc. No. 2119 ("FES sells power and provides energy-related products and services to retail and wholesale customers primarily in Illinois, Maryland, Michigan, New Jersey, Ohio and Pennsylvania.").

¹⁰¹ FirstEnergy also self-supplied in a manner similar to that described in the previous subpart. Its disclosure also revealed that its retail business purchased all of the energy from its wholesale businesses. *Id.* at 3.

¹⁰² *Id.* at 42.

¹⁰³ *Id.*

¹⁰⁴ *Id.*

¹⁰⁵ DTE Energy Comp., Annual Report (Form 10-K), at 42 (2021), <https://d18rn0p25nwr6d.cloudfront.net/CIK-0000936340/9f259cee-3e88-4889-8d37-d1efdff3d572.pdf> [<https://perma.cc/4VWJ-EZKL>] ("Various subsidiaries and equity investees of DTE Energy have entered into contracts which contain ratings triggers and are guaranteed by DTE Energy. These contracts contain provisions which allow the counterparties to require that DTE Energy post cash or letters of credit as collateral in the event that DTE Energy's credit rating is downgraded below investment grade. . . . As of December 31, 2021, DTE Energy's contractual obligation to post collateral in the form of cash or letters of credit in the event of a downgrade to below investment grade, under both hard trigger and soft trigger provisions, was \$667 million."); *id.* at 13 ("Reduced Emissions Fuel -- DTE Vantage constructed and placed in service REF [Reduced Emissions Fuel] facilities at ten sites, including facilities located at seven third-party owned coal-fired power plants. DTE Energy sold membership interests in seven of the facilities and entered into lease arrangements in two of the facilities. The facilities blended a proprietary additive with coal used in coal-fired power plants, resulting in reduced emissions of nitrogen oxide and mercury. Qualifying facilities were eligible to generate tax credits for ten years upon achieving certain criteria and ceased operations at the

These intercompany debt guarantees distort markets in at least four ways. First, they redistribute wealth from ratepayers to shareholders. Cross-affiliate debt guarantees place the generators' default risk onto ratepayers, who have to honor the generators' debt obligations if the generator is unable to meet those obligations. Cross-affiliate debt guarantees thus allow holding company shareholders to earn higher returns from an affiliate operating in competitive markets while exposing ratepayers to the risks incurred by a non-rate regulated affiliate. While this risk will have its most acute impact in the event of a default, it would have an impact even in ordinary periods, as it would increase the cost of capital borne by the rate regulated affiliate and charged to ratepayers. If a debt guarantee by a rate regulated utility raises the rate regulated utility's imputed weighted average cost of capital by 50 basis points, ratepayers will have to bear that cost.

Second, the use of cross-affiliate debt guarantees can also be understood as a form of predatory pricing by the load serving entity that purchases electricity in the wholesale market. Vertically integrated utilities typically own the retail electric providers that purchase energy from the energy market.¹⁰⁶ Because cross-affiliate debt guarantees drive the energy market price down, they reduce the price that the retail electric provider pays to purchase energy. That benefits the utility both because it reduces the price the utility pays in the wholesale market, thus increasing the regulated affiliates' profits, and because it may make it difficult for independent power producers to compete with generating units that are able to borrow at a discount.

A third problem is that cross-affiliate debt guarantees create perverse incentives for regulators. If a vertically integrated utility owns a coal-fired power plant that is at risk of defaulting on its debt, cross-affiliate debt guarantees give energy regulators an incentive to implement policies that protect their coal units. In an ideal world, the regulator would implement policies that reduce the price of energy (and, ideally, also reduce emissions). But if policies that lower energy prices would also force ratepayers to honor debt obligations incurred by the coal-fired

end of 2021 given no further eligibility.”) (alterations in original); *id.* at 129 (“DTE Energy has provided certain guarantees and indemnities in conjunction with the sales of interests in or lease of its REF facilities. The guarantees cover potential commercial, environmental, and tax-related obligations that will survive until 90 days after expiration of all applicable statutes of limitations. DTE Energy estimates that its maximum potential liability under these guarantees at December 31, 2021 was \$720 million.”).

¹⁰⁶ William Boyd & Ann E. Carlson, *Accidents of Federalism: Ratemaking and Policy Innovation in Public Utility Law*, 63 *UCLA L. Rev.* 810, 836 (2016) (“Twenty U.S. states continue to regulate electricity under a traditional cost-of-service model across all or some of their territories. Major utilities in these states are vertically integrated, selling services that bundle together generation, transmission, and distribution.”).

power plant, the regulator may be reluctant to implement such policies because it does not want to force ratepayers to honor the coal plant's debt obligations. Thus, by shifting a generators' default risk from shareholders to ratepayers, the cross-affiliate debt guarantee can create situations in which the retirement of an expensive generator whose continued operations raise the wholesale market price can, perversely, create an incentive for regulators to try to prevent the retirement of that generator.

A final problem is that cross-affiliate debt guarantees reduce transparency and increase the difficulty that regulators and investors face in understanding and supervising these enterprises. Creditors typically have an incentive to monitor and supervise debtors to protect their investments. That incentive is diminished when they expect to be bailed out by captive ratepayers. Regulators, too, can generally expect that firms will adjust their behavior in response to regulatory compliance costs. But that assumption may be incorrect when firms can pass regulatory compliance costs onto captive ratepayers. To be effective, regulators therefore have to invest additional time and money in understanding the arrangements, and they are less able to count on investors to pressure firms to comply with regulations.

III. Regulatory Cross-Subsidies

A second category of utility value transfers are subsidies to non-regulated affiliates in which the energy regulator authorizes the transfer.

A. Fuel Adjustment Clauses

Fuel adjustment clauses are one example of regulatory value transfers. Fuel adjustment clauses allow retail electric providers to adjust customer rates based on their fuel costs.¹⁰⁷ If gas or coal prices go up, the utility can automatically and

¹⁰⁷ See generally Entergy, Rate and Rate Schedule, Fuel Adjustment Clauses, https://www.entergy-arkansas.com/your_business/business_price/ [<https://perma.cc/Y5ZM-8Z68>] (“The fuel adjustment line item of a customer's bill reflects the actual cost of fuel purchased to generate electricity.”); State Corp. Comm'n of Kansas, Cost of Gas Rider, <https://www.kansasgasservice.com//media/KGS/Tariffs/40-COGR.pdf> [<https://perma.cc/WP73-9DG2>] at 2 (stating that the cost would include “actual recoveries of costs of gas”); Entergy Louisiana, Residential Rate and Rider Schedules, https://www.entergy-louisiana.com/your_home/elitariffs/ [<https://perma.cc/UGC3-4HGX>]; DTE Energy, Understanding Your Energy Bill, <https://www.newlook.dteenergy.com/wps/wcm/connect/b2e11c75-8faf-4515-80d0-c1c8759780ac/KCS-Understanding-Bill.pdf?MOD=AJPERES>

immediately increase rates to cover those increased costs, instead of having to wait for its next rate case before a public utility commission.¹⁰⁸ Such clauses might be justifiable in a context where there is nothing that the utility can do to avoid the cost and a sudden increase in cost might threaten the financial strength of the utility during the wait for the next rate case.¹⁰⁹

This imagined environment does not map onto current realities. One of the few justifications for the holding company structure is that it ought to give operating subsidiaries some financial cushion to absorb shocks to gas or coal prices.¹¹⁰ Even without a holding company structure, utilities can insulate themselves from price shifts by using long term contracts and hedging instruments, and can do so with far greater ease than retail customers.¹¹¹

[<https://perma.cc/6DYM-YL9R>]; Xcel Energy, Rate Riders, https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders [<https://perma.cc/QPH2-LMPE>]; Missouri Pub. Serv. Comm'n, Order Approving Rider Tariff Sheet (Jan. 13, 2021), <https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936328160> [<https://perma.cc/5LF4-P6RC>]; Felix Mormann, Beyond Algorithms: Toward a Normative Theory of Automated Regulation, 62 B.C. L. Rev. 1, 3-4 (2021); Richard J. Pierce, Reconsidering the Roles of Regulation and Competition in the Natural Gas Industry, 97 Harv. L. Rev. 345, 350 (1983); Russell Ernst & Sara May Bellizzi, Adjustment Clauses (Sept. 12, 2017), <https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf> [<https://perma.cc/Y7Y2-7TUH>] (describing a “fuel adjustment clause, or FAC” as “essentially a single-issue ratemaking process, whereby a utility is permitted to implement periodic rate adjustments to reflect changes in its cost of fuel.”).

¹⁰⁸ Mormann, *supra* note 107, at 20 (“Going through the normal process of applying to the state public utility commission for approval of a rate increase, followed by a complex and potentially controversial rate case proceeding, a utility would have to wait months, if not years, before being allowed to recover its increased fuel costs from consumers. . . . [F]uel adjustment clauses offer[] a timely alternative to mitigate the negative consequences of regulatory inertia.”).

¹⁰⁹ Adjustment clauses were introduced during the 1973 oil embargo when fuel costs increased too rapidly for utility companies to recoup them in general rate cases. See *id.*; see also Leaffer, *supra* note 65, at 236 (“[T]he basic aim of the [fuel adjustment clause] is to allow a utility to pass through only those inflationary costs which are beyond its control. . . .”).

¹¹⁰ Indeed, as discussed previously, some holding companies also own coal mines. See *supra* Part II.A. Even if an electricity generating subsidiary was negatively affected by an increase in coal prices, it should have little impact on the financial resources available to the overall company.

¹¹¹ Cf. Frank C. Graves & Steven H. Levine, *Managing Natural Gas Price Volatility: Principles and Practices Across the Industry*, The Brattle Grp. 1, 6 (Nov. 2010),

More fundamentally, utility companies could in theory avoid the impact of sudden increases in gas or coal prices by shifting toward cleaner and more efficient generation technologies, some of which have no fuel costs at all. Fuel adjustment clauses essentially eliminate the incentive to do so.¹¹² When coal or gas prices increase and the cost is passed through to ratepayers, ratepayers subsidize generation resources, including generators that participate in competitive auctions, thereby allowing those units to operate more frequently than they otherwise would. A generator with a fuel adjustment clause does not have to incorporate its fuel costs into its energy market bids. If it costs a generator \$35 per MWh to operate, it should

https://www.brattle.com/wp-content/uploads/2017/10/8115_managing_ng_price_volatility_graves_levine_nov_2010.pdf [perma.cc/SKZ7-U5LH] (“Several utilities started or expanded their hedging programs, to the point where now the majority of gas distribution companies use some hedging.”); Frank Graves, Philip Hanser & Greg Basheda, *Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations*, The Brattle Grp. 1, 21-22 (June 2006), https://www.brattle.com/wp-content/uploads/2017/10/6314_electric_utility_automatic_adjustment_clauses_graves_et_al_june_2006.pdf [perma.cc/82LL-TLHH] (acknowledging the availability of hedging but asserting that a well-designed automatic adjustment clauses would preserve incentives for utilities to use it). A poorly designed adjustment clause may affirmatively discourage the use of these risk management tools and may encourage the use of financial hedging instead of relatively safe long term contracts. See Ken Costello, *Survey Responses of State Utility Commissions on Long-Term Gas Contracting and Hedging*, Nat’l Regul. Rsch. Inst. 1, 7 (July 2012) <https://pubs.naruc.org/pub/FA86AF99-E13A-53C6-FACF-DBB510FEBA78> [perma.cc/3MJP-32EB] (“Most commissions allow utilities to recover the costs associated with long-term contracts through a purchased gas adjustment (PGA) mechanism on a dollar-for-dollar basis, subject to a prudence review. In other words, gas utilities do not profit from long-term contracts, and they risk cost disallowance from an after-the-fact review.”). Courts should also be careful to ensure that utilities do not use fuel adjustment clauses to support unintended activities or to shift additional risks onto ratepayers. See *Citizens of State v. Graham*, 191 So.3d 897 (Fla. 2016) (rejecting utility’s theory that its fracking operation’s expenses could be claimed under a fuel adjustment clause because the fracking operation functioned as a physical hedge).

¹¹² See Leaffer, *supra* note 65, at 235 (“The more fuel intensive the production process--however wasteful--the less risk borne by shareholders since the [Fuel Adjustment Clause] insulates the firm from any impact on profits which might result from fluctuating fuel costs.”). Professor Leaffer notes that eliminating a fuel adjustment clause may distort incentives in a different way, by encouraging utilities to over invest in fuel efficiency. But in the context of problems like scarce fuel resources or advancing climate change that are not addressed by regulation, this type of distortion might help drive utilities toward socially efficient behavior. *Id.*

not offer to sell energy for less than \$35 per MWh, since doing so would risk being forced to sell energy at a loss. However, if a generator has a fuel adjustment clause, it can recover its fuel costs from ratepayers. If it spends \$15 per MWh to purchase fuel, the same generator would be in a position to bid \$20 per MWh, since it recovers its fuel costs from ratepayers. This means the generator will operate more frequently than it otherwise would, since it can submit lower energy market bids, and it means that it will make higher profits than it otherwise would, since it has a side source of revenue.

Fuel adjustment clauses have been linked to the continued operation of carbon-intensive generators that appear to be unable to recover all their costs from energy markets.¹¹³ There is evidence that many coal-fired power plants are selling energy even when they lose money doing so. This often occurs because coal-fired power plants use a process called self-commitment, where they agree to operate regardless of the energy market price, despite the fact that self-commitment appears to be causing them to incur billions of dollars in losses.¹¹⁴ Many power

¹¹³ See Joe Daniel, *Backdoor Subsidies for Coal in the Southwest Power Pool*, *Sierra Club* 1, 24-25 (2017),

<https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf> (“This analysis has identified several coal units in SPP that incur energy production costs that far exceed that unit’s energy market revenues. This suggests that at least some utilities have identified a non-market source of revenue sufficient to cover variable costs, fixed costs, and make a profit. . . . Some utilities within SPP . . . appear to be going back to state commissions and using rate cases and other dockets to obtain ratepayer-funded subsidies for costs incurred in operating otherwise uneconomic coal plants.”); 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* 1, 20 (2019),

<https://www.sierraclub.org/sites/default/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf> [perma.cc/KL2D-3FJA] (“The pro forma pass-through of fuel costs allows regulated owners to operate coal units out of merit, or with little respect to market revenue.”); see also Joe Daniel, Sandra Sattler, Ashtin Massie & Mike Jacobs, *Used, But How Useful? How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants* 1, 38 (May 2020), <https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf> [perma.cc/T3UL-Q3VL] (listing proceedings regarding uneconomic self-committing and out-of-merit generation).

¹¹⁴ See Fisher, *supra* note 113, at 4 (estimating that in the MISO and PJM capacity markets, “coal plants with negative net revenue lost over \$3.8 billion in 2015-2017, losses that are likely being made whole via state ratemaking,” with the “vast majority of the losses (79-87%, by year) . . . incurred at coal plants owned by regulated utilities”); see Joshua C. Macey, *Zombie Energy Laws*, 73 *Vand. L. Rev.*

plants that self-commit into the energy market are affiliates of rate regulated utilities and appear to have fuel adjustment clauses that allow them to recover their fuel costs from ratepayers.¹¹⁵ These firms are therefore able to offset some, and perhaps all, of the losses they incur in energy markets because their utilities' tariffs incorporate some of their generators' costs into their distribution affiliates' tariffs.

Of course, ratepayers ultimately pay when fuel adjustment clauses cause more expensive wholesale electric providers to remain in the market, since they are still covering the generator's fuel costs. Fuel adjustment clauses can thus allow expensive incumbent generating units to remain in the market even though independent power producers could more cost effectively meet customers' energy needs.¹¹⁶

Fuel adjustment clauses are also problematic because they reduce the revenue available to other generators. Generators that submit lower energy bids cause the clearing price to go down.¹¹⁷ A generator that submits a lower bid because it recovers some of its costs through fuel adjustment clauses is therefore able to suppress the energy price. That reduces the revenue available to independent power producers, which diminishes the incentive for cleaner resources--including new solar and wind resources--to enter the market. Continuing the example above, a natural gas plant with marginal costs of \$25 per MWh would be shut out by the coal plant bidding \$20, even though the coal plant's true marginal cost is \$35. Much like the predatory pricing described above, this has the potential to distort market outcomes.¹¹⁸

Fuel adjustment clauses differ from the value transfers described in the previous Part because they occur with explicit regulatory authorization. A regulator

1077, 1108-09 (2020) (describing self-commitment process and rationale). The theoretical justification for this practice is that some types of generation have high startup and shutdown costs. It would be costly to shut down a coal plant when energy prices are low, then start it up again when prices are high. Self-commitment or self-scheduling ensures that the plant will continue to operate. *Id.* But, as discussed above, fuel adjustment clauses mean that generators do not internalize the full cost of the practice.

¹¹⁵ See *id.* at 1109-10 (“The coal generator does not mind the suppressive effect of its low bid because it recovers its energy market losses from its ratepayers. . . . [B]y using cost-of-service regulation to prolong the life of uneconomic coal generators, utilities not only increase electricity costs for consumers, but also decrease compensation for energy sources. . . .”)

¹¹⁶ See Joshua C. Macey, *Incomplete Power Markets*, 91 *U. Chi. L. Rev.* 30-42 (forthcoming 2024).

¹¹⁷ *Id.* at 1109 (“This practice allows generation facilities owned by vertically integrated utilities to manipulate competitive energy markets, which seriously distorts energy market prices and reduces revenues enjoyed by generators that could offer electricity more competitively”)

¹¹⁸ See *supra* Part II.B.

expressly allows a subset of generators to recover some of their costs from ratepayers while independent power producers rely on wholesale auctions to recover their costs. Still, the use of fuel adjustment clauses, like intercompany debt guarantees and favorable contracts to non-rate regulated suppliers, force ratepayers to subsidize affiliates that participate in unregulated markets.

B. Securitization

Holding companies also have opportunities to use utilities' financing arrangements to shift value out of rate regulated utilities. This often occurs in connection with disasters. There are three ways that a company could finance the costs of recovering from a disaster.¹¹⁹ First, the company might obtain outside insurance. But because of the increasing cost of disasters, it is increasingly uneconomical and infeasible to obtain such insurance.¹²⁰ Second, the company might take an *ex ante* approach, maintaining reserves in advance of the disaster, which it could then draw upon when those funds are needed.¹²¹ Under this approach, the company would charge extra in advance of the disaster and hold the extra money in reserve so that it can be used to pay for disaster relief. Third, the company might take an *ex post* approach by waiting until the disaster then financing the cost of recovery.¹²² In such circumstances, the company would wait until the disaster, borrow to cover the cost of recovery, and service the debt by

¹¹⁹ See Gabe Grosberg, Can U.S. Utilities Weather the Storm, S&P Glob. (Nov. 8, 2018), <https://www.spglobal.com/en/research-insights/articles/can-u-s-utilities-weather-the-storm> [perma.cc/A9SE-946B] (identifying reserve accounts, rider recovery, and securitization as three ways to finance recovery).

¹²⁰ See *id.* (noting the customer's financial burden of increased cost of protection); Iulia Gheorghiu, Kavya Balaraman, Gloria Gonzalez, Larry Pearl, Catherine Morehouse & Robert Walton, Climate Risks are Accelerating. Here's what Duke, PG&E and 16 Other Utilities Expect to Pay, Util. Dive (Nov. 18, 2020), <https://www.utilitydive.com/news/climate-risks-accelerating-heres-what-costs-duke-pge-and-16-other-utilities-expect/588860/> [perma.cc/VN42-TXVP] (noting that several utilities foresee increases in premiums as a result of climate-related disasters).

¹²¹ See Grosberg, *supra* note 119 (suggesting holding reserves in advance of disasters as a strategy).

¹²² See *id.* (describing the use of storm recovery riders and securitization); Scott Carpenter, As Climate Damage Rises, Utilities Turn to 'Recovery Bonds', Wash. Post (Nov. 29, 2022), https://www.washingtonpost.com/business/as-climate-damage-rises-utilities-turn-to-recovery-bonds/2022/11/29/c4e9edfa-6ffa-11ed-867c-8ec695e4afcd_story.html [perma.cc/FE9X-JC3B] (describing the role of recovery bonds in financing repairs from climate damage).

charging extra. Both ex ante and ex post strategies can create opportunities for mischief.

At least in principle, ex ante strategies like self-insurance and reserves could create opportunities for value transfers. Self-insurance at the parent level might mean that the rate-regulated subsidiary is on the hook for disaster costs that ought to be borne by a subsidiary in a competitive market. For example, if a disaster damages a generation facility operating in a competitive market, the parent might try to recoup or finance the cost of recovery by squeezing its rate-regulated subsidiaries. Imposing reserve requirements on the rate-regulated subsidiaries could also create opportunities for self-dealing: customers would contribute cash in advance, which the company would be able to invest and to hold.¹²³ Absent careful analysis and policing, that capital can be used to create profits or to overstate the financial strength of the overall company.

But ex post strategies create far greater opportunities for mischief. As noted previously, one of the basic principles of rate regulation is that the rate regulated utility is entitled to an opportunity to earn a return on its investment.¹²⁴ A company, for example, might be guaranteed a 10% return on the capital it invests in the enterprise. If a storm hits and the company spends \$500 million to repair the damage, this guarantee suggests that the company is entitled to \$50 million in carrying costs after one year. In essence, the company would have loaned the ratepayers \$500 million at 10% interest. In our opinion, these returns are extremely high given that the debt is effectively backed by a guarantee from the state or local government--the authorities are required to raise rates charged to customers by an incremental amount that is sufficient to pay off the debt. Authorizing utilities to earn a return on disaster relief programs also leads to moral hazard, since utilities may be disinclined to make preventative investments that would reduce the likelihood and costs of disasters if they know that they will earn a profit responding to the disaster after it occurs.

But the problems of ex post strategies are further underscored by “securitization” mechanisms. Securitization allows a company to set up a separate, bankruptcy-remote entity that issues bonds to the public markets and uses the proceeds to buy the right to receive the incremental amounts being charged to

¹²³ The value of this type of activity should not be understated. Insurers earn much if not all of their profits by investing the “float”--money paid in by insureds in premiums that has not yet been paid out in claims. The success of firms like Berkshire Hathaway is largely based on the profits that they have extracted from this activity. See Warren Buffett, Letter to Shareholders, Berkshire Hathaway 2, 6 (Feb. 26, 2010), <https://www.berkshirehathaway.com/letters/2009ltr.pdf> [perma.cc/CKW2-K58X] (“Insurers receive premiums upfront and pay claims later. . . . Meanwhile, we get to invest this float for Berkshire’s benefit.”).

¹²⁴ See supra Part I.

ratepayers.¹²⁵ To continue the example above, after a year of handling the cost of the recovery, the company might set up a new shell entity. The shell entity would raise \$560 million by selling bonds to the public, then pay that sum over to the company--\$500 million for the actual cost of the recovery, \$50 million in carrying costs or interest, and \$10 million for the cost of setting up the transaction. In exchange, the company would receive the right to receive the incremental amounts from ratepayers. The shell entity would then pay off the bonds over time. The bonds issued to investors have essentially the same risk profile and characteristics as the original amount: the company effectively loaned ratepayers \$500 million to cover the cost of recovery and was guaranteed a return; that debt was refinanced into a debt to investors, still backed by the same guarantee. But while the company was effectively guaranteed 10% interest, investors seem willing to buy the bonds at much lower rates.¹²⁶

For example, in 2008, Hurricanes Gustav and Ike seriously damaged Entergy's operations.¹²⁷ In an order on August 18, 2009, the Public Utility Commission of Texas concluded that Entergy Texas, Inc. was entitled to recover over \$500 million in spending to restore service after the disaster, and that the

¹²⁵ Carpenter, *supra*. See SEC, Prospectus Supplement (to Prospectus Dated October 23, 2009), https://www.sec.gov/Archives/edgar/data/1427437/000006598409000214/d424b5.htm#stoc18461_4 [perma.cc/U68P-8T5H] (describing the creation of a "bankruptcy remote special purpose subsidiary company" that would issue bonds and purchase the right to receive "transition charges" paid by retail electric customers and set by a public utility commission at a rate guaranteed to ensure recovery).

¹²⁶ See Jennifer Hiller, *Utility Bills Rise as Americans Pay Off Storm-Recovery Costs for Decades to Come*, *Wall St. J.* (Dec. 11, 2022), <https://www.wsj.com/articles/utility-bills-rise-as-americans-pay-off-storm-recovery-costs-for-decades-to-come-11670714171> [perma.cc/U6NH-R8KQ] (suggesting that "an electric or gas utility's typical borrowing" is normally at a higher rate than what can be obtained in a securitization). Although the rate charged by the investors through bonds is low relative to the rate charged by the utility company, it may still be too high. The rate paid to investors is ultimately borne by utility customers, and the utility company and its advisors have little incentive to work to keep that rate down. See Carpenter, *supra* note 122 ("What's the attraction? Companies issuing recovery bonds aren't on the hook to pay them back out of their own coffers.")

¹²⁷ Entergy Texas, Inc., No. 36931, Pub. Util. Comm'n Tex., (Aug. 18, 2009), https://interchange.puc.texas.gov/Documents/36931_399_623827.PDF [perma.cc/T8XS-HVRR] at ¶ 1; see also Ike, Gustav to cost Entergy at least \$1 billion, *NBC News* (Sept. 30, 2008), <https://www.nbcnews.com/id/wbna26957996> [perma.cc/WN5F-4L4H] (estimating hurricanes Ike and Gustav cost Entergy \$1 to \$1.2 billion).

company was entitled to 10.86% interest on its expenditures.¹²⁸ In effect, this made ratepayers responsible for paying the company 10.86% interest until the company was paid back. To pay it off, ratepayers were charged an extra incremental amount.¹²⁹ A new entity, Entergy Texas Restoration Funding, LLC issued bonds at a rates of 2.12% to 4.38% in October 2009, then used the proceeds to buy the right to collect that extra increment from Entergy Texas.¹³⁰ In terms of the economic consequences, Entergy Texas effectively loaned money to ratepayers at over 10% interest, and ratepayers ultimately refinanced at less than 5% interest.

It is not obvious why Entergy should have been entitled to charge 10.86% interest. Statutorily, Entergy was entitled to charge its weighted average cost of capital, as found during the latest general ratemaking.¹³¹ But that weighted average cost of capital ought to reflect the cost of raising capital in public markets.¹³² The fact that public markets were ultimately willing to lend at 4.38% interest or less casts doubt on the determination that Entergy was entitled to 10.86%. While some difference might be expected, or even intended,¹³³ the

¹²⁸ Entergy Texas, Inc., No. 36931, Pub. Util. Comm'n Tex., (Aug. 18, 2009), https://interchange.puc.texas.gov/Documents/36931_399_623827.PDF [perma.cc/T8XS-HVRR] at ¶ 18.

¹²⁹ Application of Entergy Texas, Inc. for a Financing Order 7 (Sept. 11, 2009) https://interchange.puc.texas.gov/Documents/37247_63_625732.PDF [perma.cc/R9GW-5UAV] (describing “transition charges” paid by “retail electric customers”).

¹³⁰ Prospectus Supplement (To Prospectus Dated October 23, 2009) \$545,900,000 Entergy Texas Restoration Funding, LLC, at S-11, https://www.sec.gov/Archives/edgar/data/1427437/000006598409000214/d424b5.htm#stoc18461_4 [perma.cc/U68P-8T5H]. The transaction was approved by the Public Utility Commission of Texas in a financing order on September 11, 2009. Application of Entergy Texas, Inc. for a Financing Order 1 (Sept. 11, 2009) https://interchange.puc.texas.gov/Documents/37247_63_625732.PDF [perma.cc/R9GW-5UAV].

¹³¹ See Tex. Util. Code Ann. § 36.402(b) (West 2021) (“System restoration costs shall include carrying costs at the electric utility's weighted average cost of capital as last approved by the commission in a general rate proceeding from the date on which the system restoration costs were incurred until the date that transition bonds are issued or until system restoration costs are otherwise recovered pursuant to the provisions of this subchapter.”)

¹³² The Texas PUC stipulated that a reasonable return on equity is 10% in a March 2009 order. Application of Entergy Gulf States, Inc. for Authority to Charge Rates and to Reconcile Fuel Costs https://interchange.puc.texas.gov/Documents/34800_2046_611798.PDF [perma.cc/2ZF4-5V9G] at ¶ 25.

¹³³ Texas created the securitization mechanism “based on the conclusion that securitized financing will result in lower carrying costs for utility assets relative to

magnitude of the difference is surprising. And the interest was not cheap. Entergy pocketed over \$40 million in carrying costs from these transactions.¹³⁴

Similarly, Duke Energy's operations in North Carolina were affected by Hurricanes Florence, Michael, Dorian, and Winter Storm Diego.¹³⁵ North Carolina regulators allowed one Duke subsidiary, Duke Energy Progress, to recoup storm costs of \$714 million, including "approximately \$78.1 million in carrying costs calculated using the Company's approved weighted average cost of capital through August 31, 2020."¹³⁶ Those amounts were eventually folded into a securitization,¹³⁷ with bonds offered to the public in November 2021.¹³⁸ Duke effectively charged ratepayers 6.93 percent interest for carrying the cost,¹³⁹ while the investing public charged less than three percent.¹⁴⁰

the costs that would be incurred using conventional utility financing methods." Application of Entergy Texas, Inc. For a Financing Order 6 https://interchange.puc.texas.gov/Documents/37247_63_625732.PDF [perma.cc/R9GW-5UAV] at 6.

¹³⁴ See *id.* at 1.

¹³⁵ Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice 189 <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=31a43e38-3985-400a-89c5-5afbf7828cb6> [perma.cc/2SLF-5KF2].

¹³⁶ *Id.* at ¶ 56.

¹³⁷ See Financing Order in the Matter of Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC For Issuance of a Storm Cost Recovery Docket Financing Order 5-6, <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=04b1c72c-f024-40d3-a9bf-d00079e2ee1e> [<https://perma.cc/VV4Z-T4VW>] (describing Duke's request to issue Storm Recovery Bonds).

¹³⁸ Duke Energy, 2021 Annual Report and Form 10-K 124, <https://desitecore10prod.cd.azureedge.net/annual-report/-/media/pdfs/our-company/investors/de-annual-reports/2021/2021-duke-energy-annual-report.pdf?rev=f3700925e6134fc6a138ad691d82a6e9> [perma.cc/XQ38-QT8K].

¹³⁹ Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice 17 <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=31a43e38-3985-400a-89c5-5afbf7828cb6> [perma.cc/2SLF-5KF2] (allowing Duke to earn a 6.93% rate of return on the cost of their property).

¹⁴⁰ \$769,627,000 Series A Storm Recovery Bonds, Duke Energy Progress, LLC (cover page) https://www.sec.gov/Archives/edgar/data/1881229/000110465921141981/tm2126671-12_424b1.htm (showing interest rates of 1.295%, 2.387%, and 2.799% on the three tranches of debt in the offering to the public).

IV. Investment Decisions

Finally, rate regulated utilities can transfer value by making investment decisions that protect their non-regulated affiliates. This occurs when utilities construct transmission lines that favor their generating affiliates, own a diverse portfolio of resources that give them incentive to resist climate reforms (e.g. electric utilities may resist electrification efforts because they worry that their gas assets will become stranded), and expand into related business lines such as electric vehicle charging and demand response. We discuss the first two--because in our opinion, they have the highest stakes both in terms of emissions reductions and economic costs--but it is worth noting that this issue arises whenever utilities seek to expand into new markets.

A. Affiliated Gas and Electric Utilities

Energy companies often own both gas and electric subsidiaries. This can lead to inefficient investments, as companies may make investment decisions that reduce conflicts between the two subsidiaries.¹⁴¹ Instead of having the electric subsidiary compete aggressively with the gas subsidiary, the company could simply continue to harvest returns from its existing gas business. The effect is comparable to owning coal mines¹⁴² or coal plants,¹⁴³ in that the company has an incentive to keep customers hooked on a less efficient fuel.

Approximately 47 percent of American households are heated using natural gas, while only 36 percent are heated using electric furnaces or heat pumps.¹⁴⁴ Although natural gas is not the dirtiest fossil fuel, it is ultimately a hydrocarbon that releases energy by being burned.¹⁴⁵ Unlike electricity, which is increasingly

¹⁴¹ For a similar analysis, see Troy A. Rule, *Utility Mission Creep*, 56 U.C. Davis L. Rev. 591, 593-94 (2022) (outlining the dangers of “utility mission creep” and offering potential policy solutions).

¹⁴² See *supra* Section II.a.i.

¹⁴³ See *supra* Section IV.b

¹⁴⁴ See U.S. Energy Info. Admin., *U.S. Households’ Heating Equipment Choices Are Diverse and Vary by Climate Region*, EIA (Apr. 6, 2017), [https://www.eia.gov/todayinenergy/detail.php?id=30672&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20\(RECS\)-f2](https://www.eia.gov/todayinenergy/detail.php?id=30672&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-f2) [perma.cc/KL4T-P4KL].

¹⁴⁵ See e.g. U.S. Energy Info. Admin., *Natural Gas Explained*, EIA (last updated Nov. 7, 2022), <https://www.eia.gov/energyexplained/natural-gas/natural-gas-and-the-environment.php> [https://perma.cc/DF3F-7NFR]. The production and

provided from renewable sources,¹⁴⁶ natural gas cannot be a completely clean source of heating energy because methane is a potent greenhouse gas. As a result, transitioning from natural gas to electricity is a worthwhile step in addressing the threat of climate change.¹⁴⁷

Widespread electrification is more likely to occur if the companies that are charged with connecting transportation and heating systems to the grid will not suffer financial losses as a result. However, because energy companies often own both gas and electric utilities, the companies that need to replace gas infrastructure that currently heats most homes and buildings will be stranding the gas assets that their gas utilities own. It should thus come as little surprise that companies that own both gas and electric utilities occasionally drag their feet when encouraging individuals to switch than companies that own only electric utilities. For example, Pacific Gas and Electric has declined to provide incentives to encourage customers to switch from gas to electric, but Southern California Edison made aggressive plans to capture business from Southern California Gas Company.¹⁴⁸

These incentives can also distort investment behavior. An electric company that is eager to take market share from a gas company has a clear incentive to build generation and transmission capacity, but an electric company that is content to maintain a status quo vis-à-vis its gas company affiliate lacks that incentive.

B. Transmission Decisions

Another important type of utility value transfer occurs when utilities make transmission investment decisions that appear to be designed to protect their

distribution of natural gas can also have environmental impacts, including through the release of methane from active and abandoned natural gas wells.

¹⁴⁶ See Renewables Became the Second-Most Prevalent U.S. Electricity Source in 2020, Energy Info. Admin. (July 28, 2021), <https://www.eia.gov/todayinenergy/detail.php?id=48896> [perma.cc/VD6Z-CY47] (discussing renewable sources becoming the second-most prevalent source of electricity).

¹⁴⁷ See generally, Emma Penrod, Transition Away From Natural Gas Necessary to Meet Climate Goals but Creates Equity Concerns, Experts Say, UtilityDive (June 2, 2021), <https://www.utilitydive.com/news/transition-away-from-natural-gas-necessary-to-meet-climate-goals-but-creat/600975/> [perma.cc/3X2S-PR7M].

¹⁴⁸ Justin Gerdes, What Does It Take to Electrify Everything in Your Home?, GreenTech Media (Apr. 2, 2018), <https://www.greentechmedia.com/articles/read/what-does-it-take-to-electrify-everything-in-your-home> [perma.cc/3XX4-PT2J] (comparing Southern California Edison's ambitions for using electric power and PG&E's policies forbidding them from encouraging fuel-switching).

generation assets. Here, too, conflicts of interest lead utilities to make (or not make) investments in rate regulated markets that protect their non-rate regulated assets.

Deep decarbonization requires a significant investment in transmission infrastructure.¹⁴⁹ Solar and wind resources are usually located far from population centers that consume large amounts of electric energy. To transport energy generated from solar and wind, utilities need to build transmission that would give new wind and solar developments access to large consumer markets. Additional transmission is also important for grid reliability, since it allows regions that are experiencing generation capacity constraints to import power from neighboring regions.¹⁵⁰ Transmission is also economically beneficial since it expands the market available to less expensive generating units. Finally, by increasing the number of resources that can meet consumers' energy needs, transmission lines reduce generators' ability to exercise market power, since they open energy markets up to competition from additional resources. A generator that might have been able to raise the energy price by submitting higher bids or withholding supply may be unable to do so if additional generators are able to supply energy to the region it serves.

Transmission policy in the United States is extremely complicated. Large regional lines are supposed to be planned in regional transmission planning

¹⁴⁹ See supra note 16; Nadja Popovich & Brad Plumer, *Why the U.S. Electric Grid Isn't Ready for the Energy Transition*, N.Y. Times (June 12, 2023), <https://www.nytimes.com/interactive/2023/06/12/climate/us-electric-grid-energy-transition.html> ("America's fragmented electric grid, which was largely built to accommodate coal and gas plants, is becoming a major obstacle to efforts to fight climate change."); Jesse D. Jenkins, Jamil Farbes, Ryan Jones, Neha Patankar & Greg Schivley, *Electricity Transmission Is Key To Unlock the Full Potential of the Inflation Reduction Act*, REPEAT Project, at 4 (Sept. 22, 2022) https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf [perma.cc/35JD-D87H] (finding that, to meet the Inflation Reduction Act's emissions goals, the United States needs to double the pace of transmission investments); Klass, et al., supra note 15, at 1034-35; Catherine Clifford, *Fierce Local Battles Over Power Lines Are a Bottleneck for Clean Energy*, CNBC (June 26, 2022, 4:22 PM), <https://www.cnbc.com/2022/06/26/why-the-us-has-a-massive-power-line-problem.html> [perma.cc/H4KZ-UZ4Q] (noting that "the bulk of the capacity for wind and solar . . . are not where the majority of the American population lives[,] but that additional transmission is opposed by various groups including incumbent utilities with market power).

¹⁵⁰ For example, part of the reason ERCOT, the grid operator responsible for Texas, fared worse than other grids in managing Winter Storm Uri because it lacked transmission capacity to transfer power from adjacent grids. See February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, FERC (Feb. 2021), <https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-full> at 10.

processes in which regional planning entities oversee competitive solicitations to determine which companies construct new lines.¹⁵¹ That process appears to be broken, however, since it now accounts for very few new transmission lines.¹⁵² This is perhaps because FERC has given utilities an incentive to build local lines instead of regional ones by exempting local lines from the requirement that new lines undergo competitive solicitations.¹⁵³ Since utilities do not face competition from merchant transmission operators when they build lines outside of the regional process, they may prefer to invest in local projects to make sure that they do not face competition from merchant developers.¹⁵⁴ By building local lines, however, utilities reduce the need for regional solutions that would more economically meet their region's transmission needs and allow more renewables to connect to the grid.¹⁵⁵

Another reason utilities may favor local projects is that these projects face little regulatory oversight. Often, the only meaningful review of new lines occurs when the utility applies to its PUC for a certificate of public convenience and necessity. Many states, however, do not require small lines to apply for a certificate of public convenience and necessity. For example, in California, lines that have a relatively low voltage or built on existing rights of way do not need a certificate of public convenience and necessity.¹⁵⁶ In the past three years, sixty-three percent of

¹⁵¹ See generally *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order 1000, 136 FERC ¶ 61,051, para. 78-85, 259 18 C.F.R. § 35 (2011) (describing reforms that need to be made to regional transmission planning).

¹⁵² *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, Para. 40-41 (Apr. 21, 2022) (“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.”).

¹⁵³ We use the phrase “local lines” as a catch-all to refer to all new transmission lines that are built outside of the regional transmission planning process.

¹⁵⁴ See Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 *Energy L. J.* 1, 29-41 (2021) (explaining the ways utilities may attempt to avoid competition in transmission development).

¹⁵⁵ See *id.*

¹⁵⁶ See Pub. Utilities Comm’n of the State of Cal. Gen. Order No. 131-D, *Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California § III.A*, at 2 (Sept. 10, 1995), <https://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF> [perma.cc/4E2Z-32PN] (finding of “public convenience and necessity” is necessary for “major electric

all lines built in California have been self-approved because they were tailored to fit the exemptions from the certificate of public convenience and necessity process.¹⁵⁷ That means a majority of new lines built in California have had virtually no regulatory oversight.

While it is possible that utilities are simply shifting to the path of least regulatory resistance and trying to make sure that they--rather than competitor merchant transmission operators--construct new lines, there is reason to think that transmission operators are also making transmission investments strategically to protect their generation assets. By building low voltage local lines instead of regional ones, transmission operators reduce the need for large lines that would expose their generation assets to competition from neighboring regions.¹⁵⁸

Consider Entergy's determined opposition to MISO regional transmission plans.¹⁵⁹ In 2016, MISO approved a 230 kV line that would have increased connections with Entergy's service territory. The line would have cost just over \$100

transmission line facilities which are designed for immediate or eventual operation at 200kV or more," except for replacements, minor relocations, or conversions of existing lines).

¹⁵⁷ See State of Cal. Pub. Utilities Commission, Letter Re: Technical Conference on Transmission Planning and Cost Management Docket No. AD22-8-000, at 109-10 (Sept. 16, 2022) (stating that sixty-three percent of transmission investment by the three largest transmission owners has been self-approved and unreviewed).

¹⁵⁸ See Popovich & Plumer, *supra* note ("Utilities are sometimes wary of long-distance transmission lines that might undercut their local monopolies.").

¹⁵⁹ Entergy's involvement in MISO itself raises related concerns. Entergy Louisiana joined MISO while under antitrust scrutiny from the Justice Department. Entergy alleviated the Justice Department's concerns that it could exclude more efficient generators by promising to integrate with MISO's capacity market and divest its transmission business. See Justice Dep't Statement on Entergy Corp.'s Transmission System Commitments and Acquisition of KGen Power Corp.'s Plants in Arkansas and Mississippi (Nov. 14, 2012), <https://www.justice.gov/opa/pr/justice-department-statement-entergy-corp-s-transmission-system-commitments-and-acquisition> [perma.cc/LT5F-8Y99]. However, Entergy did not end up divesting its transmission business. See Entergy, ITC Discontinue Pursuit of Transmission Spin/Merger, Entergy (Dec. 13, 2013), <https://www.entergynewsroom.com/news/entergy-itc-discontinue-pursuit-transmission-spin-merger/> [perma.cc/D8ZB-7ENA]. Nevertheless, it did follow through on joining MISO. Entergy's choice of MISO was suspect. Entergy was more connected with the Southwest Power Pool (SPP); joining the SPP would have allowed more power to flow back and forth. See Daniel Tait, Records Reveal Entergy's Role in Stalling MISO Transmission Planning, Energy & Policy Institute (Apr. 5, 2021), <https://www.energyandpolicy.org/entergy-role-stalling-miso-transmission-planning/> [perma.cc/5VXE-2ZL4].

million and yielded significant economic benefits.¹⁶⁰ However, in 2020, Entergy intervened in the regional planning process and argued that the line was no longer cost-justified.¹⁶¹ One reason that Entergy had received approval to build a major gas-fired power plant.¹⁶² The utility pointed out that the plant would provide many of the reliability benefits that MISO had used to justify the transmission line.¹⁶³ MISO agreed, finding that the line could be no longer needed. Entergy therefore spent nearly a billion dollars to build a gas-fired generator that eliminated the need for a regional transmission line. In doing so, Entergy ensured that its existing generation infrastructure did not have to compete with generators in MISO. Entergy appears to have engaged in similar behavior when it eliminated the need to build a \$115 million line connecting two towns in Texas (Hartburg and Sabine) by building a 1.2 GW combined-cycle gas plant at a cost of approximately \$1 billion.¹⁶⁴

V. Solutions

Utility value transfers distort energy markets in a few ways. The most direct way this occurs is by increasing energy costs. When ratepayers take on some of the risks undertaken by non-regulated affiliates, they allow those affiliates to operate even if they would otherwise be unable to cover their costs. Doing so ensures that uneconomic units remain online and thus forces ratepayers to pay an above-market price for energy. Second, value transfers undermine climate regulations and other forms of state and federal policy. Clean energy subsidies and carbon taxes are less effective when buyers of fossil resources are not responsive to market forces. For example, when coal mines sell coal to rate regulated affiliates, they do not need to worry that they will lose customers to subsidized wind and solar. And third, they reduce financial stakeholders' incentives to exert control over corporate decision-

¹⁶⁰ See generally Comments Of Southern Renewable Energy Association (“SREA”), Building for the Future Through Electric Regional Docket No. RM21-17-000 Transmission Planning and Cost Allocation and Generator Interconnection, <https://www.govinfo.gov/content/pkg/FR-2022-05-04/pdf/2022-08973.pdf> [perma.cc/5N5H-8SF7].

¹⁶¹ ISO Waterford Churchill 230kV Economic Project Withdrawal Technical Studies Task Force Meeting (TSTF) at 3, (Oct. 9, 2020), <https://cdn.misoenergy.org/20201009%20STSTF%20Waterford%20-%20Churchill%20230kV%20Economic%20Project%20Withdrawal482098.pdf> [https://perma.cc/75JK-7EAD]

¹⁶² See SREA, *supra* note 160. MISO Waterford Churchill 230kV Economic Project Withdrawal Technical Studies Task Force Meeting (TSTF) (Oct. 9, 2020), <https://cdn.misoenergy.org/20201009%20STSTF%20Waterford%20-%20Churchill%20230kV%20Economic%20Project%20Withdrawal482098.pdf> [https://perma.cc/75JK-7EAD].

¹⁶³ See SREA, *supra* note 160.

¹⁶⁴ *Id.*

making. Creditors and shareholders ordinarily push firms to make financially sound investments because they want to protect their investments. However, because ratepayer guarantees reduce the risks creditors and shareholders face if an investment does not work out, they reduce creditor and shareholder incentives to supervise and monitor corporate decisions.

Perhaps the most effective way to respond to these regulatory challenges is to make it impossible for utilities to transfer value from ratepayers to shareholders-- either by eliminating rate regulation altogether or by forcing utilities to spin off their non-rate regulated affiliates. Full corporate unbundling would quarantine rate regulated energy firms so that they cannot engage in intercompany value transfers. Should these reforms prove infeasible, regulators should consider more targeted interventions such as forced disclosure and more aggressive oversight of intercompany value transfers to police the behavior described above.

A. Public Ownership or Control

The issue of value transfers is traceable to the system of rate regulation in which a subsidiary is granted a legal monopoly and guaranteed a rate of return on its investments. This system of rate regulation is intended to address the problems associated with private ownership of critical assets that form a natural monopoly. For example, it only makes sense to have one set of lines running to each home. If those lines are to be owned by a private party, that private party must be given an incentive to make any necessary investments while being barred from taking advantage of suppliers and customers.

One answer to value transfers would be to avoid rate regulation altogether. Instead of using rate regulation to control the problems associated with private ownership, regulators could reduce barriers to entry or place the assets in public hands.¹⁶⁵ It is not clear what would be lost from a transition to public ownership. Under rate regulation, utility companies already lack incentives to innovate, are not disciplined by competition, and do not receive informative signals from real price or market mechanisms. And government actors already must enmesh themselves in company operations, deciding what expenses are appropriate and what rate of return is appropriate. Public ownership would simply return profits to the public. To the extent that outside operational expertise is required, the authorities could hire it in a competitive bidding process.¹⁶⁶

¹⁶⁵ Cf. Shelley Welton, *Public Energy*, 92 N.Y.U. L. Rev. 267, 314-20 (2016) (proposing a framework to evaluate city takeovers of electric utilities and discussing obstacles facing municipalization).

¹⁶⁶ See Harold Demsetz, *Why Regulate Utilities?*, 11 J.L. & Econ. 55, 57 (1968) (suggesting that rate regulation is not the only solution to problems of natural monopolies, and that it might be replaced with competitive bidding for the right to operate the relevant productive assets). But see Oliver E. Williamson, *Franchise Bidding For Natural Monopolies--in General and with Respect to CATV*, 7 Bell J.

A less radical alternative would be to involve the ratepaying public in the governance of these firms.¹⁶⁷ Putting ratepayer representatives on the board of directors of the relevant subsidiaries would help in identifying and policing value transfers. That vehicle for internal regulation would be particularly valuable if it was combined with robust external regulation, in which public authorities reacted forcefully to warnings and red flags from ratepayer representatives on the board. And if the ratepayer representatives had more power than the shareholder representatives, they could check value transfers directly.

B. Breaking Up Holding Companies

Another cause of value transfers is the holding company structure in which one company owns rate regulated subsidiaries and subsidiaries in competitive markets. Without that structure, there would be little motive or opportunity to engage in value transfers through transactions within the corporate group.

One answer would be to break up holding companies. Doing so would be consistent with William Baxter's view that regulators should "quarantine" public utilities.¹⁶⁸ The PUHCA model would be one approach to this. The statute assumed that some scale and integration could create operational efficiencies--it allowed vertical integration within a geographically continuous area--but concluded that all other forms of integration created risks that exceeded the benefits.¹⁶⁹ Although the calculus could be adjusted, the basic prescription of viewing synergies skeptically and breaking up holding companies would defeat the problems that arise when

Econ. 73, 74 (1976) (noting that bidding for a franchise may create difficult contracting problems); Victor P. Goldberg, Regulation and Administered Contracts, 7 Bell J. Econ. 426, 428 (1976) (suggesting that concepts based on discrete transactions are not well suited to long-term relational contexts). Admittedly, government ownership would not be a complete solution for the problems presented here. Government actors can also be risk-averse, seek to protect prior investments, or transfer value through debt guarantees and other mechanisms. But the personal financial incentives to engage in this type of behavior would be greatly reduced.

¹⁶⁷ Kovvali & Macey, *The Corporate Governance of Public Utilities*, supra note 23 at 9 (proposing reforms that give residual authority to ratepayers); Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 Cal. L. Rev. 209, 227 (2021) (discussing the notable governance structure of PJM, which allows those with ownership interests in any PJM sector to become a voting member).

¹⁶⁸ See sources cited supra note 16.

¹⁶⁹ Karmel, supra note 25 at 852-854 (discussing the PUHCA's key provisions and proposing the PUHCA as a model for handling large financial institutions).

vertically integrated firms transfer value from rate regulated affiliates to affiliates that participate in competitive markets.¹⁷⁰

C. Stricter Regulation

A narrower intervention would use existing institutional structures to address value transfers. Most obviously, regulators could use existing standards and authorities in a more skeptical and aggressive manner to address the problems identified here. In principle, regulators already examine mergers and financing transactions. The analysis here suggests that they should look harder. Similarly, regulators should take a closer look at pricing of affiliate transactions and the short-term and long-term efficiency of utility investments.¹⁷¹

¹⁷⁰ Importantly, this would not necessarily punish shareholders. The holding company structure allows managers to use financial and regulatory complexity to transfer value from ratepayers to shareholders. But it also allows managers to obscure pure performance and uninspired leadership. It is no accident that strategies for unlocking shareholder value often focus on breaking up large companies. Cf. Rory Van Loo, *In Defense of Breakups: Administering a "Radical" Remedy*, 105 *Cornell L. Rev.* 1955, 1958 (2020) (urging that breakups are not a radical or destructive remedy, and that regulators should be more willing to employ it). Indeed, this strategy has even made an appearance within the energy space. In a recent engagement, activist investor Elliott pressed Duke Energy to consider breaking itself up into three companies, in the hope that the breakup would unlock additional shareholder value. Rithika Krishna & David French, *Activist Elliott Calls for Three-Way Split of U.S. Utility Duke*, Reuters (May 17, 2021), <https://www.reuters.com/business/energy/activist-investor-elliott-urges-duke-energy-consider-three-way-separation-2021-05-17/> [perma.cc/GT8J-59KN]. Elliott later exited its position in Duke. Megan Davies & Svea Herbst-Bayliss, *Elliott Dissolves Stake in Duke Energy, Discloses Stake in Suncor*, Reuters (May 16, 2022), <https://www.reuters.com/markets/us/elliott-dissolves-stake-duke-energy-discloses-stake-suncor-2022-05-16/> [perma.cc/883A-A3GA] (discussing Elliott's dissolution of its stake in Duke Energy). It is not clear which effect will dominate—shareholders may gain more than they lose from large and opaque corporate structures. See Paul G. Mahoney, *The Public Utility Pyramids*, 41 *J. Legal Stud.* 37, 38-40 (2012) (arguing that shareholders benefited from pyramid structures, as evidenced by market reactions to key events surrounding the enactment of PUHCA, and attributing this to monitoring by controlling shareholders at the top of the pyramid). However, the inherent technical complexity of the energy industry may make shareholders in these companies particularly unable to monitor managers or defend their interests.

¹⁷¹ For example, regulators might overcome some of the challenges associated with fuel adjustment clauses by using indexed rather than actual prices to prevent a

Regulators might also consider measures that would enhance their ability to identify value transfers. Most obviously, investing in state capacity--hiring additional experts, sharing knowledge and expertise across regulators, enhancing regulatory transparency and accountability--would help regulators to do their job. Expanded disclosures would allow regulators to crowdsource analysis.¹⁷² Indeed, the case for disclosure may be overdetermined: It is not obvious that financial investors fully understand the risks and benefits associated with their positions.¹⁷³

Another set of interventions might focus on enhancing the credibility of rate regulation. A debt guarantee by a rate regulated subsidiary only has limited value unless investors believe that the subsidiary will be squeezed to make good on the obligation. In effect, it is a bet that regulators will fail to do their job. Demonstrating a serious commitment to preventing value transfers would help unravel the strategy.¹⁷⁴

holding company from using a fuel adjustment clause to subsidize an inefficient affiliate that creates the fuel, and by testing the “prudence” of utility company decisions by questioning whether the company is making efficient investment and operating decisions. See, e.g., Paul L. Joskow & Richard Schmalensee, *Incentive Regulation for Electric Utilities*, 4 *Yale J. Regul.* 1, 9, 32 (1986) (explaining how a prudence test requires efficient investment in the long-term and discussing arguments for an indexed rate provision); Daniel, *supra* note 113 at 30-31 (“During rate cases, state commissions could disallow recovery of costs for fuel and variable and operating and maintenance expenses that were incurred during periods of time when plants were running uneconomically. . . . Insofar as utilities are incurring expenses at utility-owned generation above market prices to deliver power to their customers from other (non-utility) plants, those above-market costs are imprudent and should not be borne by customers.”).

¹⁷² As one element of this, regulators ought to consider expanding public access to material filed by utilities during rate cases. Due to the lack of competition, normal concerns about proprietary technical or business information are not present in this space. As matters stand, it is difficult for outside researchers to detect problems (or check reasonable hypotheses) by consulting the dockets at public utility commissions.

¹⁷³ See *supra* Part I (discussing investor losses caused by financial complexity); cf. Ann Lipton, *Not Everything is About Investors: The Case for Mandatory Stakeholder Disclosure*, 37 *Yale J. on Regul.* 499, 534 (2020) (advocating expanded mandates for disclosures to non-investor audiences and highlighting relationship with investor-focused disclosures).

¹⁷⁴ Cf. Steven L. Schwarcz, *Ring-Fencing*, 87 *S. Cal. L. Rev.* 69, 78, 85-88, 93 (2013) (examining ring-fencing, a regulatory solution that aims to place assets or risks into separate legal entities to manage or prevent problems).

Conclusion

New Dealers recognized that size and financial complexity created unique dangers in the utility space, where companies are entitled to an opportunity to earn a return on their investments and ratepayers are not protected by competition. Over time, the old lessons have been forgotten, and holding companies have developed a new set of tools to transfer value from rate regulated subsidiaries to subsidiaries operating in supposedly competitive markets. The resulting distortions have extracted value from ratepayers, exposed ratepayers to new financial risks, and compromised regulatory priorities on matters like disaster preparedness and slowing climate change. Better policing of value transfers has the potential to curb these problems and help improve the energy industry.