RETOOLING RATEMAKING: ADDRESSING PERVERSE INCENTIVES IN WHOLESALE TRANSMISSION RATES

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Abstract: All regulatory systems create incentives; unfortunately, even the most well-intentioned incentives can have perverse consequences. The incentives created by traditional utility rate regulation—for purposes of this article we focus on the regulation of electric transmission rates by the Federal Energy Regulatory Commission (FERC)—are no exception. Under traditional cost-of-service ratemaking, utilities have a powerful incentive to increase capital investments and reduce operating expenses in order to boost returns for shareholders. In this article, we focus on what occurs when utilities act on the perverse incentive to inappropriately reduce operating expenses so as to increase profits. Whether it is tree trimming or work performed on electro-mechanical equipment, maintenance deferred too long can lead to avoidable failures that are more frequent, more prolonged, and more severe than they would otherwise be, resulting in power outages, an uptick in repair or replacement costs—or in the most extreme circumstances, wildfires that can ravage whole towns, with the toll measured not just in dollars, but also in human lives.

In this article, we argue that addressing this perverse incentive is a core component of FERC's obligation to ensure that rates are just and reasonable, and discuss the versatile array of tools at FERC's disposal with which it can ensure that rate regulation acts to maintain safe and reliable service rather than compromise it. In Part I, we discuss the perverse incentives associated with cost-of-service ratemaking and examine the potentially disastrous consequences that can ensue if the perverse incentive to reduce operating expenses leads to behavior that compromises safety and reliability. In Part II, we review both FERC enforcement, generally, and North American Electric Reliability Corporation (NERC) reliability standards, specifically, and conclude that remedying this perverse incentive requires viewing it less as an issue with service quality, and more as a ratemaking problem. In Part III, we discuss the array of ratemaking tools at FERC's disposal—return on equity (ROE) determinations, prudence reviews, performance-based ratemaking (PBR), and trackers or earmarked funds—and examine how FERC could use each of these tools to ensure that authorized rates help maintain, rather than work against, a utility's provision of safe and reliable service. We conclude that FERC should use these tools more rigorously to ensure that utilities

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are not unjustly and unreasonably securing higher profits for themselves by inappropriately reducing operating costs, and that authorized rates are used to maintain safe and reliable service, thereby protecting consumer interests and ensuring grid reliability.

I. INTRODUCTION

It is well-recognized that “every regulation imposed by government creates limitations on what [regulated entities] can do; but every regulation also gives the [regulated entity] incentives to act in ways (driven generally by the desire to maximize net income, or earnings) that may or may not promote the public interest.”[1] Accordingly, even the most well-intentioned incentive can have “perverse consequences—even in some cases, causing [regulated entities] to work against the goal [the regulator was] trying to achieve.”[2] The incentives created by traditional utility

1. Jim Lazar et al., REGULATORY ASSISTANCE PROJECT, *Electricity Regulation in the U.S.: A Guide*, REGULATORY ASSISTANCE PROJECT 6 (Mar. 2011), https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricityregulationintheus-guide-2011-03.pdf.

2. FORBES, *Perverse Incentives* (Feb. 20, 2009), https://www.forbes.com/2009/02/19/incentives-compensation-bonuses-leadership_perverted_incentives.html?sh=5f39f055b3b7.

ratemaking are no exception. This article discusses ratemaking at FERC, which regulates, among other things, electric transmission rates.

Many FERC-jurisdictional rates are derived using traditional cost-of-service ratemaking, which "allow[s] utilities to recover operating costs and a return on investment on all capital costs."[3] This structure has always risked incentivizing utilities[4] to skimp on maintenance spending in order to pad their ROEs. To the extent that this perverse incentive leads to behaviors that compromise safety and reliability, the results can include catastrophic equipment failures, destruction of enormous amounts of both public and private property, or even loss of life—as has occurred, most notably in the case of the Camp Fire in Northern California, sparked by Pacific Gas & Electric Company (PG&E) equipment in 2018.

By and large, FERC has lagged behind many states in recognizing and mitigating this issue—and some might argue that FERC is not the appropriate agency to address this particular perverse incentive. For instance, while states can ensure minimum utility performance through state quality standards, the Federal Power Act (FPA) does not give FERC similar authority to enforce general service quality standards at the federal level. Moreover, it may be impractical— and would certainly be expensive—to task FERC—or NERC, the FERC-certified electric reliability organization (ERO)—with setting detailed, comprehensive standards to ensure this type of utility performance, as that would require a drastic expansion of these agencies' scope.[5]

However, while FERC may not have the authority to prescribe service quality standards, it *does* have the authority and obligation to set just and reasonable transmission rates. By their nature, those rates include the costs that utilities request to maintain their transmission facilities. Those same transmission facilities are then integral to safe and reliable service.

Indeed, it is axiomatic that the reasonableness of a rate—literally, the price of service—cannot be judged in a vacuum; as "price really has no meaning except in terms of an assumed quality of service."[6] In other words, because "buyers can be exploited just as effectively by giving them poor or unsafe service as by charging them excessive prices,"[7] "[a] reduction in quality is a hidden price increase."[8]

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3. Sidney A. Shapiro and Joseph P. Tomain, *Realizing the Promise of Electricity Deregulation: Rethinking Reform of Electricity Markets*, 40 WAKE FOREST L. REV. 497, 508 (2005).

4. This article focuses on investor-owned utilities, and the incentives they face. Other entities, like generation and transmission cooperatives or municipal utilities, face different incentives because they do not operate under the same rate regulation structures or have the same need to attract capital. *See e.g.* Laurence D. Kirsch et al., *Alternative Electricity Ratemaking Mechanisms Adopted by Other States*, CHRISTENSEN ASSOC.'S ENERGY CONSULTING, at iv, 1, 6 (May 15, 2016), https://www.caenergy.com/wp-content/uploads/2016/02/Kirsch_Morey_Alternative_Ratemaking_Mechanisms.pdf.

5. *See*, *infra*, Part II.

6. ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, Vol. 1 at 21; *see also Am. Tel. & Tel. Co. v. Cent. Off. Tel., Inc.,* 524 U.S. 214, 215 (1998) (J. Scalia) ("Since rates have meaning only when one knows the services to which they are attached, any claim for excessive rates can be couched as a claim for inadequate services and vice versa.").

7. KAHN, *supra* note 6, at 21.

8. Richard Green, et al., *Resetting Price Controls for Privatized Utilities*, ECONOMIC DEVELOPMENT INSTITUTE OF THE WORLD BANK 82 (Feb. 1999), http://regulationbodyofknowledge.org/wp-content/uploads/2014/02/PriceControlsForPrivatizedUtilities1999WB.pdf.

Accordingly, what is needed is less a shift in law and more a shift in perspective. FERC should think of its jurisdiction as encompassing more than just setting rates at a theoretically appropriate numerical level. Ensuring that customers are getting the safe and reliable service that they pay for is just as core a component of FERC's ratemaking responsibility—i.e., the responsibility to consider price in relation to the service provided.

As a legal matter, FERC already has an array of tools at its disposal with which to ensure rate regulation acts to maintain safe and reliable service rather than compromise it. Most of these stem directly from the FPA, including ROE determinations, prudence reviews, performance-based ratemaking, and trackers or earmarked funds. FERC should use these tools more rigorously to ensure that utilities are not unjustly and unreasonably securing higher profits for themselves by inappropriately reducing operating costs and that authorized rates are used to maintain safe and reliable service, thereby protecting consumer interests and ensuring grid reliability.

II. THE IMPACT OF THE PERVERSE INCENTIVES ASSOCIATED WITH TRADITIONAL RATEMAKING ON SERVICE QUALITY

A. The Interplay between Quality of Service and the Fundamentals of Utility Ratemaking

Over the years, price regulation in many traditionally regulated industries—the aviation and telecommunications industries, most notably— has steadily been replaced by free-market constructs. And in some cases—with the rise of retail choice at the state level and market-based wholesale power sales at the federal level—this is true for electric utilities as well. But it is not true for at least one segment of the utility business: wholesale service over transmission lines is still regulated by FERC using many of the same traditional ratemaking principles that have been employed for generations.

The well-known, oft-repeated mantra of the utility regulator is that rates must be "just and reasonable." FPA section 205,[9] under which FERC regulates interstate transmission rates and wholesale power sales,[10] is entitled "Just and Reasonable Rates" and reads:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[11]

This provision, vague as it may first seem, forms the backbone of FERC rate regulation. Similar provisions provide a parallel mandate to most—if not all—

9. 16 U.S.C. § 824d.

10. This article will primarily focus on transmission rates when it discusses FERC regulation; FERC has largely, albeit not entirely, gone over to a market-based rate concept for sales of electric energy.

11. 16 U.S.C. § 824d(a).

state public utility commissions for their regulation of retail sales and distribution services.

The rates awarded by utility commissions are bounded on the low end by the concept of a "reasonable return." In 1923, in *Bluefield*,[12] the Supreme Court explained thusly:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[13]

As such,

> [a] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable . . . ventures.[14]

A little more than two decades later, in *Hope,*[15] the Court expounded on this doctrine in the context of reviewing a decision made by FERC's predecessor, the Federal Power Commission (FPC), on natural gas rates. The FPC, it noted, was given "broad powers of regulation," at the heart of which was "[t]he fixing of 'just and reasonable' rates . . . with powers attendant thereto."[16] As such, the Court ruled,

> [r]ates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base.[17]

But ensuring the seller an opportunity to earn an adequate return is only one side of the "just and reasonable" equation. Rates are bounded on *both* sides to form a "zone of reasonableness."[18] Rates that are too low are unjust, unreasonable, and confiscatory of utilities, just as rates that are too high are unjust, unreasonable,

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12. Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of West Virginia, 262 U.S. 679 (1923).

13. *Id.* at 690.

14. *Id.* at 692-93.

15. Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

16. *Id.* at 611 (internal citation omitted).

17. *Id.* at 605.

18. Maine v. FERC, 854 F.3d 9, 21 (D.C. Cir. 2017) ("To calculate the ROE for a utility that is not publicly traded, FERC relies on the ROEs for a 'proxy group' of comparable publicly traded companies. After adjusting that range of ROEs to exclude unrepresentative high or low rates, 'the Commission assembles a zone of reasonable ROEs on which to base a utility's ROE.' The zone of reasonableness is intended to balance the interests of investors and consumers, and typically results in a broad range of potentially reasonable ROEs. After assembling this zone of reasonableness, FERC assesses the utility's circumstances to determine whether to make 'pragmatic adjustment[s]' to the rate.") (internal citations omitted).

and exploitive of customers. Indeed, as the Supreme Court has repeatedly recognized, the FPA is, above all, a consumer protection statute.[19] For instance, in *FERC v. EPSA*, the Supreme Court characterized the FPA's core objectives thusly: "The statute aims to protect 'against excessive prices' and ensure effective transmission of electric power."[20] In other words: in addition to its statutory obligation to set "just and reasonable rates," FERC must also (1) ensure prices are sufficient to secure safe and reliable service while (2) protecting consumers against excessive prices (with "the consumer's interest" ultimately "[being] paramount").[21]

These obligations are sometimes thought of as competing—or even conflicting. But, in these authors' opinion, protecting consumers from being charged excessive prices and ensuring safe and reliable service are not in tension. The reasonableness of a service's price cannot be judged in a vacuum; as "[p]rice really has no meaning except in terms of an assumed quality of service."[22] In other words, because "[b]uyers can be exploited just as effectively by giving them poor or unsafe service as by charging them excessive prices,"[23] "[a] reduction in quality is a hidden price increase."[24] Therefore, price, safety, and reliability are all inextricably connected, and the consumer's receipt of safe and reliable service is a key component of what makes a rate "just and reasonable."

Unfortunately, traditional ratemaking tools, particularly those associated with cost-of-service rates, can create perverse incentives for utilities that can ultimately endanger consumers' receipt of the safe and reliable service that they paid for—or worse.

B. Traditional Ratemaking Can Establish Perverse Incentives

Bluefield and *Hope*, discussed above, clearly delineate the fundamental principle of cost-of-service ratemaking: utilities are entitled to a reasonable opportunity to recover their prudently-incurred costs plus a reasonable return. In the decades that have followed, ratemaking at FERC and at state utility commissions has tended to focus on precisely that: cost. Utilities, of course, argue that their rates and especially their rates of return are too low. Consumers argue that they are too high. Often, settlements are reached somewhere in the middle; if they are not, litigation ensues over each cost item.

Traditionally, and often still, cost-of-service rates are based on a fixed annual revenue requirement.[25] Essentially, when a utility files a stated rate at FERC or at

19. *See, e.g.*, FERC v. Elec. Power Supply Ass'n, 136 S.Ct. 760 (2016); Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty., Wash., 554 U.S. 527, 551 (2008); Mun. Light Boards of Reading & Wakefield, Mass. v. FPC, 450 F.2d 1341, 1348 (D.C. Cir. 1971).

20. *FERC v. EPSA*, 136 S. Ct. at 781 (internal citations omitted).

21. *Williams Pipe Line Co.*, 21 FERC ¶ 61,260, 61,583 (1982), *reh'g denied* 22 FERC ¶ 61,086 (1983).

22. KAHN, *supra* note 6, at 21.

23. *Id.*

24. Green, *supra* note 8, at 82.

25. These rates are also known as "stated rates." *See e.g.* Darryl Tietjen, *Tariff Development 1: The Basic Ratemaking Process*, PUB. UTIL. COMM'N OF TEXAS 1 (2021).

a state commission, it includes an estimate for each component of its cost of service (usually based on a historical test year),[26] such as administrative, general, and operations and maintenance expenses; taxes; and depreciation.[27] It also proposes a rate of return (its weighted average cost of capital) on the net (depreciated) value of its utility investments (rate base). The sum is a number that is supposed to be the total amount the utility needs to run its operations for the year (i.e., its revenue requirement).[28] To derive rates, the revenue requirement is then "divided among functions (like generation, transmission, distribution, and customer service) . . . allocated among customer classes (like residential, commercial, industrial, and street lighting), and then assigned to billing determinants (like electrical energy consumed, peak power demand, and fixed monthly fees)."[29] Often this is done by using a forecasted load number—i.e., a utility's "reasonable when made" estimate of how much its sales and other load (such as losses) will be in a given year.

Two aspects of this system combine to create particular incentives for the filing utility. First, the rates are not trued up to actual expenditures—the utility recovers its authorized rate regardless of whether its actual costs end up being higher or lower than its forecasted ones and regardless of whether its actual sales end up being higher or lower than forecast. Second, the funds received in rates are not earmarked: the component costs are used to support a rate determination, but the actual revenue collected from rates may be spent on any legitimate business purpose, retained, or even distributed as dividends to investors.

Independently, each of these features could be seen as desirable. For instance, the lack of a true-up can incentivize efficiency by urging utilities to "practice operating economies and to stimulate growth of demand for service."[30] Likewise, the lack of earmarking can give utilities the flexibility they need to operate under real-world conditions and avoid micromanagement of utility operations by regulators.

However, it has long been acknowledged that this structure also creates problematic incentives. Commenters have noted that cost-of-service ratemaking "biases a regulated firm . . . toward more capital-intensive modes of production" where the "purchased capital becomes part of the utility's rate base upon which an allowed or approved rate of return may be earned."[31] Put more simply, utilities may perform unnecessary capital work on which they earn a return rather than cheaper, simpler operations and maintenance work on which they don't. Also,

26. *See, e.g.,* Branko Terzic, *Incentive Regulation: Efficiency in Monopoly*, 8 NAT. RES. & ENV'T 3, 28 (Winter 1994) ("In the current ratemaking scheme as practiced in most regulatory jurisdictions, an annual revenue requirement is determined based on projections in a test year and is then divided by the estimate of annual sales, which results in the simplest regulatory ratemaking formula."); *See also* 18 C.F.R. § 35.13 (a),(c),(d),(h) (requirements for certain utility rate change filings, including cost-of-service analysis for defined test periods).

27. Terzic, *supra* note 26, at 28.

28. *Id.*

29. Laurence D. Kirsch et al., *Alternative Electricity Ratemaking Mechanisms Adopted by Other States*, CHRISTENSEN ASSOC.'S ENERGY CONSULTING 3 (May 15, 2016), https://www.caenergy.com/wp-content/uploads/2016/02/Kirsch_Morey_Alternative_Ratemaking_Mechanisms.pdf.

30. JAMES C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 96 (2d ed. 1988).

31. *Id.* at 356 (discussing Averch-Johnson thesis).

under this system "[a] profit-driven [utility] may pay more attention to short-term gains" or "may cut costs in a way that affects reliability."[32] It is the lack of earmarking that allows the utility the budgetary discretion to shift dollars (whether to inefficient capital projects or to dividends). And it is the lack of a true-up that allows the utility to keep any excess profits it reaps.

Specifically, the two features discussed above combine to form the perverse incentive on which we focus: high maintenance costs claimed for ratemaking purposes, followed by actual underspending on maintenance in order to boost profits to the long-term detriment of safety and reliability. This is not a new issue—and as demonstrated above, we are not the first authors to take this question up. However, the risks posed by maintenance failures have only grown with an increased population and associated dependency on electricity, challenging anew the acceptability of this skewed incentive. Moreover, extreme weather conditions due to climate change can make maintenance failures that were once all but unnoticeable catastrophically dangerous.[33] One high profile case in particular illustrates what can happen when these fundamental changes collide with an outdated paradigm of sloppy maintenance practices: seemingly benign lapses can compound over many years before disastrous results surface. We discuss that example and others, and propose some possible tools that FERC can use to mitigate these dangers.

C. Perverse Incentives in Utility Ratemaking Can Lead to Catastrophic Consequences

In the long term, exploitation of cost-of-service ratemaking incentives can lead—and has led—to catastrophic equipment failures, destruction of enormous amounts of both public and private property, and even loss of life, as will be discussed below.

As a rule, though, these instances can (initially) be hard to spot. When customers and customer advocates in rate cases are focused on costs alone, they might not dig into the data to notice when the company is skimping on maintenance. And when they see underspending on maintenance or capital work or any other aspect of utility operations, they might take that as an opportunity to argue for a rate reduction, rather than push for more money to be spent to preserve the system.

For this reason, it is interesting to look at cases where the consequences were not catastrophic, but where the utility's cost-cutting strategy became apparent over the course of several rate cases. This played out in Tennessee and West Virginia, where two subsidiaries of the American Water Works Company, the Tennessee and West Virginia American Water Companies, sought rate increases from the state public utility commissions. In both cases, the two utilities ran relatively small

32. Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 ENVTL. L. 435, 459 (2002) (citing Charles H. Koch, Jr., *Control and Governance of Transmission Organizations in the Restructured Electricity Industry*, 27 FLA. ST. U.L. REV. 569, 590-97 (2000)).

33. *See e.g.,* U.S. DEP'T OF ENERGY, NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY 23 (2020) (noting that the increase in severe weather impacts (and our increased vulnerabilities to the same) have only underscored that a robust transmission network is critical).

water systems in discrete parts of their state, which allowed the relevant commissions to look at their rate requests on a more detailed level than most large utility requests. It became clear that both attempted to recover the costs of more full-time personnel than they actually retained, all while skimping on maintenance and continuing to pay dividends to their upstream corporate parent.[34]

For instance, in its 2011 rate case, the Tennessee American Water Company asked for authorization to recover the costs of 110 employees in rates—which would suggest plans to significantly increase staff from existing levels.[35] In fact, the company's authorized personnel levels steadily *decreased* from a high of 107 in 2009 to 87 full-time employees by the time of its 2011 rate request (although it had been authorized to recover the costs of 109 employees in its previous rate request).[36] On the stand, the company's president admitted that maintenance had been behind schedule. As justification for falling behind on maintenance while laying off personnel, he stated: "2010 was going to be a year that did not nearly approach the 10.2% return on equity and we're continuing to decline. So at that point, we had to do what we could to manage the business."[37] Doing what was needed to manage the business did *not*, however, involve decreasing the dividends paid by the Tennessee American Water Company to its upstream corporate parent—the American Water Works Company.[38]

Similarly, in its 2010 rate case, the West Virginia American Water Company testified that it needed 316 full-time employees to maintain "adequate" service to its customers. The company's president went so far as to say on the stand that he did not believe that the company "[could] achieve any additional cost savings in head count."[39] The West Virginia Public Service Commission, relying on this testimony despite requests from other parties in the case that it decrease the authorized headcount, thus granted the company's requested authorization. A few weeks later, the company announced that it was laying off thirty-one employees and significantly decreasing its investment in distribution infrastructure. The com-

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34. One of the authors, Katharine Mapes, was involved in these cases, representing the Utility Workers Union of America and its relevant locals in a series of proceedings at the Tennessee Regulatory Authority and at the West Virginia Public Service Commission. Along with Anree Little, Ms. Mapes also participated in the briefing of PG&E's "TO18" rate case before FERC, FERC Docket No. ER16-2320 (July 29, 2016), on behalf of the Northern California Power Agency and the California Department of Water Resources; she also represented clients in the PG&E "TO18" litigation. All views put forth in this article are the authors' own and should not be attributed to their clients, past or present.

35. Transcript of Direct Test. of John Watson at 21: 14-17, *Tennessee American Water Co.*, Docket No.10-00189 (Tenn. Regulatory Authority Sep. 23, 2010), http://share.tn.gov/tra/orders/2010/1000189a.pdf.

36. Transcript of Direct Test. of James Lewis at 5:1-6:3, *Tennessee American Water Co.*, Docket No. 10-00189 (Tenn. Regulatory Authority Jan. 5, 2011), http://share.tn.gov/tra/orders/2010/1000189ez.pdf.

37. Cross-examination of John S. Watson, Vol. II.C, Tr. 342:20-25, *Tennessee American Water Co.*, Docket No. 10-00189 (Tenn. Regulatory Authority Mar. 1, 2011).

38. *Id*. Tr. 345:6-13, 346:4-13 (Watson conceding that no consideration was given to reducing the dividend in light of the maintenance needs and purported revenue shortfalls).

39. Transcript of Direct Testimony of Wayne D. Morgan at 31:18-32:1, *West Virginia-American Water Co.*, Case No. 10-0920-W-42T (W. Va. Pub. Serv. Comm'n Aug. 2, 2010).

pany admitted that this would cause reliability problems. In a subsequent investigation by the West Virginia Public Service Commission into the reductions in force, the company's president stated:

> [W]e anticipate that the Staffing Reductions may affect the Company's response time on main breaks. Moreover, over time, the possibility of more main breaks exists, because we have been unable, due to a reduction in discretionary investment, to increase the pace of distribution infrastructure replacement.[40]

The company nonetheless justified its decision on the ground that it received less in rate relief (i.e., a lower revenue requirement) than it had asked for and, thus, argued that it needed to make cuts in other places[41]—unstated but yet easily understood was that it needed to do this to maintain profits at an acceptable level for its parent company.

In this case, the company's plan was thwarted, at least temporarily, by the West Virginia Public Service Commission, which put an initial order in place enjoining the layoffs and requiring the company to keep itself fully staffed. Ultimately, after a full investigation, it enjoined some of the layoffs—those that it deemed to bear directly on the safety and reliability of the company's service—until the company's next rate case. The West Virginia Public Service Commission concluded that it would

> not wait for actual service problems to support a finding that the actions of [the company] are unreasonable. The requirement for evidence of unreasonable acts or practices can be based on reasonable expectations and does not require the Commission to wait until the facilities of a utility are so poor that consumer complaints increase to unprecedented levels or result in instances of dangerous conditions or inadequate service.[42]

The Tennessee and West Virginia American Water Company rate cases are interesting because of how specific the evidence was that the companies shorted service quality in exchange for shareholder profits. For larger utilities, state commissions cannot and do not drill down to individual job titles and, of necessity, take a broader view. This is true of rate cases at FERC as well. However, that does not mean that FERC and stakeholders cannot get valuable information in those cases, as PG&E's "TO18" rate case,[43] discussed below, shows.

PG&E provides gas and electric power to large swathes of Northern California. Its service territory includes most of the San Francisco Bay Area, including San Francisco itself, Oakland, and San Jose. It also includes more sparsely populated portions of the state, such as communities located in the Sierra Nevada

40. Transcript of Direct Testimony of Wayne D. Morgan at 16:10-13, *West Virginia American Water Co*., Case No. 11-0740-W-GI (W. Va. Pub. Serv. Comm'n June 29, 2011).

41. *See, e.g.,* Transcript of Rebuttal Testimony of Wayne D. Morgan at 5:14-18, *West Virginia American Water Co*., Case No. 10-0920-W-42T (W. Va. Pub. Serv. Comm'n Nov. 22, 2010), http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=309752&NotType=%27WebDocket%27.

42. Commission Order, *West Virginia American Water Co*., Case No. 11-0740-W-GI at 15 (W. Va. Pub. Util. Comm'n Oct. 13, 2011), http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=330867&NotType=%27WebDocket%27.

43. *Pac. Gas and Elec. Co.*, 175 FERC ¶ 61,040 at P 1 (2021).

Mountains.[44] Thus, in addition to maintaining systems in densely populated urban areas (above and below ground), it must also maintain transmission and distribution systems in mountainous areas prone to high winds and wildfires.[45]

PG&E has been no stranger to the headlines in general—for instance, in 2001, it declared bankruptcy in the aftermath of the California market meltdown at the turn of the millennium.[46] But PG&E entered a new phase of well-publicized safety troubles in September 2010, when one of its gas pipelines exploded in San Bruno, California, killing eight people, destroying thirty-five homes, and damaging many more. PG&E's gas distribution system is under the jurisdiction of the California Public Utilities Commission (CPUC).[47] Thus, when the San Bruno pipeline exploded, the CPUC initiated a long-running investigation (which itself generated various scandals and controversies).[48] It discovered "that the San Bruno incident was caused by a combination of multiple contributing factors," including PG&E's repeated violations of the Public Utilities Code and federal regulations, and general mismanagement.[49] For instance: "PG&E had collected $224 million

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44. CALIFORNIA ENERGY COMM'N, *Energy Maps of California: Electric Utility Service Area Map* (2020), https://cecgis-caenergy.opendata.arcgis.com/documents/c69c363cafd64ad2a761afd6f1211442/explore; CALIFO RNIA ENERGY COMM'N, *Energy Maps of California: Electric Utility Service Territories and Balancing Authorities* (2017), https://cecgis-caenergy.opendata.arcgis.com/documents/electric-utility-service-territories-and-balancing-authorities/explore.

45. *See, e.g.,* Maggie Angst, *Northern California wildfires scorch more than 158,000 acres: PG&E may be partly to blame*, THE MERCURY NEWS (Jul. 19, 2021), https://www.mercurynews.com/2021/07/19/northern-california-wildfires-scorch-more-than-158000-acres-as-pge-reveals-it-may-have-sparked-the-dixie-fire/(discuss ing the Dixie, Tamarack, and Beckwourth Complex Fires, all of which started between late June and mid-July 2021, and which, as of July 19, 2021, "continue to scorch more than 158,000 acres of bone dry forest landscape in Northern California", all in or near PG&E's service territory). By August 27, 2021, the Dixie Fire—only 46% contained—had become the largest fire in California's history, burning over 750,000 acres. Anisca Miles, *Massive Dixie Fire burns over 750K acres, 46% contained*, FOX40 (Aug. 27, 2021), https://fox40.com/news/wildfire-watch/dixie-fire-burns-over-750k-acres-is-46-contained/.

46. John Farrell, *Twice Burned, Once Shy—Why Californians Should Be Wary of Bailing Out PG&E Again*, GREENTECH MEDIA (Jan. 21, 2019), https://www.greentechmedia.com/articles/read/twice-burned-once-shywhy-californians-should-be-wary-of-bailing-out-pge-aga ("The last time Pacific Gas & Electric declared bankruptcy, in 2001, its customers paid billions of dollars in higher rates while company creditors and shareholders lost little. In that case, PG&E's losses were largely due to deregulation and marketplace manipulations by Enron and others.").

47. CAL. PUB. UTIL. COMM'N, *Natural Gas and California*, https://www.cpuc.ca.gov/natural_gas/ ("The California Public Utilities Commission (Commission or CPUC) regulates natural gas utility rates and services provided by Pacific Gas and Electric Company (PG&E) . . . [t]he natural gas services which the CPUC regulates include in-state transportation of natural gas over the utilities' extensive transmission and distribution pipeline systems, gas storage, procurement, metering and billing.").

48. For instance, "PUC commissioners and officials, including former President Michael Peevey, were criticized for improper communications with executives at Pacific Gas & Electric Co.," including ex parte conversations regarding "how much to fine PG&E for the 2010 explosion of a natural gas transmission line that killed eight people in the Bay Area city of San Bruno." *See e.g.,* Ivan Penn, *PUC gets public input on reform amid outcry over its practices*, LOS ANGELES TIMES (Aug. 12, 2015), https://www.latimes.com/business/la-fi-puc-overhaul-20150813-story.html.

49. CALIFORNIA PUB. UTILS. COMM'N, *September 9, 2010 PG&E Pipeline Rupture in San Bruno*, CONSUMER PROTECTION & SAFETY DIVISION INCIDENT INVESTIGATION REPORT 3-4 (Jan. 12, 2012) ("CPSD's investigation conclude[d] that the San Bruno incident was caused by a combination of multiple contributing factors: 1. PG&E's failure to follow accepted industry practices when it constructed Segment 180 in 1956; 2.

more than it was authorized to collect in oil and gas revenue in the decade before the explosion. At the same time, it spent millions less than it was supposed to on maintenance and generally fell short of industry safety standards."[50]

Ultimately, the legal consequences to PG&E were far-reaching. The CPUC fined PG&E $1.6 billion at the conclusion of its investigation, at that point the largest fine ever levied against a utility in the United States.[51] PG&E also committed to making $2.8 billion of shareholder-funded improvements to its gas distribution system.[52] Unusually, PG&E itself was also convicted by a federal jury on five charges of violating federal pipeline safety regulations and of obstructing a National Transportation Safety Board investigation (although none of its individual officers and employees were charged).[53] The judge ultimately sentenced PG&E to the harshest sentence allowable under law: a $3 million fine and five years of probation, to expire in January 2022.[54] Of course, this punishment was dwarfed by the CPUC fines (and damages paid out in individual claims brought by victims and families).[55]

PG&E's failure to comply with the integrity management requirements 3. PG&E's inadequate record keeping practices; 4. Deficiencies in PG&E's SCADA system and inadequate procedures related to the work at the Milpitas Terminal and PG&E's failure to comply with its own procedures; 5. PG&E's deficient emergency response actions after the incident; and 6. PG&E's corporate culture emphasizing profits over safety. The investigation found the following code violations: 1. PG&E did not follow the accepted industry standards specified in ASA B31.1.8-1955 when it installed Segment 180 in 1956 and therefore violated the Public Utilities Code, Section 451; 2. PG&E violated Code of Federal Regulations (CFR) 49, Part 192, Subpart O, for its failure to comply with the integrity management requirements; 3. PG&E failed to keep adequate records for Segment 180 and failed comply with the industry standards specified in ASA B31.1.8-195 and therefore violated the Public Utilities Code, Section 451; 4. PG&E violated 49 CFR Parts 192.605(c) and 192.13(c) for its failure to establish adequate procedures for recognizing abnormal operating conditions at the Milpitas Terminal and for not following its own procedures; 5. PG&E failed to timely test employees at the Milpitas Terminal for alcohol and therefore violated Part 199.225; 6. PG&E violated the Public Utilities Code, Section 451 for allowing deficiencies to exist in its SCADA system which interfered with its ability to detect and respond to the emergency; 7. PG&E violated Parts 192.605 and 192.615 and Public Utilities Code Section 451 for inadequately responding to a major incident and jeopardizing public safety.").

50. Morgan McFall-Johnsen, *Over 1,500 California Fires in the Past 6 years — Including the Deadliest Ever —Were Caused by One Company: PG&E. Here's What it Could Have Done but Didn't*, BUSINESS INSIDER (Nov. 3, 2019), https://www.businessinsider.com/pge-caused-california-wildfires-safety-measures-2019-10.

51. George Avalos, *PG&E Slapped with Record $1.6 Billion Penalty for Fatal San Bruno Explosion*, THE MERCURY NEWS (last updated Aug. 12, 2016), https://www.mercurynews.com/2015/04/09/pge-slapped-with-record-1-6-billion-penalty-for-fatal-san-bruno-explosion/.

52. PG&E would later be fined $1.9 billion for its role in multiple "catastrophic 2017 and 2018 wildfires," which "were unprecedented in size, scope, destruction, and loss of life"—including the deadly Camp Fire in November 2018. Press Release, *California Pub. Utils. Comm'n, CPUC Penalizes PG&E $2 Billion for 2017 and 2018 Wildfires* (May 7, 2020), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M337/K016/337016958.PDF.

53. George Avalos, *PG&E gets Maximum Sentence for San Bruno Crimes*, THE MERCURY NEWS (last updated Jan. 27, 2017), https://www.mercurynews.com/2017/01/26/pge-gets-maximum-sentence-for-san-bruno-crimes.

54. *Id.* PG&E was also ordered to run a television ad campaign explaining its convictions, punishment, and steps toward remediation.

55. Lisa Pickoff-White, David Marks & Alex Emslie, *PG&E Gets $3M Fine for San Bruno Blast, Must Advertise its Conviction on TV*, KQED.ORG (Jan. 26, 2017), https://www.kqed.org/news/11287618/pge-gets-3m-fine-for-san-bruno-blast-must-advertise-its-conviction-on-tv.

Then, in 2017, twenty-one major wildfires fires swept through California's wine country. The California Department of Forestry and Fire Protection (Cal Fire) found that all but one— the Tubbs Fire[56]—involved PG&E's equipment.[57] In total, 22 people died in those fires.[58] Ultimately, Cal Fire found that at least three of the fires were caused by PG&E violations of California law[59]—specifically "Section 4293 of the California Public Resources Code, which requires utilities to maintain a specified clearance between any part of the tree and energized power lines and to remove all hazardous trees or limbs that might fall on the lines."[60] Regarding at least some of the fires, the CPUC's Safety and Enforcement Division (SED) also alleged that PG&E violated numerous CPUC rules and regulations.[61] Nevertheless, PG&E did not face charges in connection with these fires.

One year later, in November 2018, PG&E's equipment sparked the Camp Fire—the deadliest fire in California's history—which raged for seventeen days in Butte County, California. By the time the fire was extinguished, 85 people had lost their lives and the towns of Paradise and Concow were virtually destroyed.

That PG&E's equipment—specifically, one of PG&E's transmission lines—was responsible for starting the fire was readily apparent. Investigators quickly determined that in the early morning of November 8, a suspension hook (C hook) that held up an insulator string connecting an energized power line (or jumper

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56. PG&E reached a settlement with eighteen victims of the Tubbs Fire who claimed PG&E was responsible for the blaze; under the deal, PG&E agreed to pay $13.5 billion to victims of fires occurring in 2015, 2017 and 2018, including the Tubbs Fire. J.D. Morris, *PG&E: Judge Approves Tubbs Fire Settlements*, SAN FRANCISCO CHRONICLE (Jan. 30, 2020), https://www.sfchronicle.com/business/article/PG-E-Judge-approves-Tubbs-Fire-settlements-15014806.php.

57. PG&E Corp., Quarterly Report Pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the quarterly period ended June 30, 2019, (Form 10-Q) 46 (Aug. 9, 2019).

58. Order Modifying Conditions of Probation at 2, United States v. Pac. Gas and Elec. Co., No. CR 14-0175 WHA, (N.D. Cal. Apr. 29, 2020) (Doc. 1186) (hereinafter Order Modifying Conditions of Probation).

59. *Id.* (As opposed to other equipment failures that were not necessarily caused by illegal conduct).

60. *Id.*

61. Joint Motion of Pacific Gas and Electric Company (U 39 E), The Safety and Enforcement Division of the California Public Utilities Commission, Coalition for California Utility Employees, and the Office of Safety Advocate for Approval of the Settlement Agreement at 3-4, No. I.19-06-015 (Cal. Pub. Utils. Comm'n June 27, 2019). The alleged violations include:

> (a) [General Order] 95, Rule 19, for disposing of evidence related to a reported incident and Commission investigation; (b) GO 95, Rule 31.1, for failing to identify and abate dying, diseased or weakened trees and tree parts; improper performance of vegetation management activities, such as pruning, removal, etc.; failing to perform a complete patrol of its system and according to best practices described in PG&E procedures; failing to retain documents related to vegetation inspections and a work order; late completion of work orders according to PG&E's own procedures; and for PG&E's records indicating that a work order had been completed when, in fact, the work had not been performed; (c) GO 95, Rule 35, for allowing vegetation to contact energized, bare conductors operating at distribution voltages, and for improperly prioritizing and deferring abatement of vegetation straining and abrading a secondary/service voltage conductor; (d) GO 95, Rule 38, for allowing two energized conductors of the same circuit to make contact thus violating minimum clearance requirements; and (e) Resolution E-4184 for failing to report one of the fire locations in the Potter/Redwood Fire.

Id.

conductor) to the transposition arm of a transposition tower (Tower 27/222)[62] on the nearly 100-year-old Caribou-Palermo line failed, having "worn through after a great deal of time hanging in the windy environs [where it was located]."[63] This failure

> allow[ed] the energized jumper conductor to make contact with the steel tower structure. The ensuing electrical arcing between the jumper conductor and steel tower structure caused the aluminum strands of the conductor to melt as well as a portion of the steel tower structure. The molten aluminum and steel fell to the brush covered ground at the base of the steel tower structure. This molten metal ignited the dry brush.[64]

Aided by high winds, the fire spread rapidly.

California has an unusual legal structure in place called "inverse condemnation," under which utilities can be held responsible for damages caused by fires started by their equipment even if those fires were not caused by negligence or other malfeasance.[65] This doctrine has worried California utilities for years—given the increasingly fire-prone conditions in the state due to climate change, even a prudently-operated utility could spark a catastrophic wildfire.

It soon became clear, however, that PG&E had *not* prudently operated its utility. Though the Caribou-Palermo line had been constructed nearly 100 years earlier, many original components were still in use.[66] For instance, many of the transposition components on Tower 27/222, "including the transposition arms, C hooks, insulator strings and jumper conductor, were original components in service since 1921."[67] In particular, "the insulator string hanging from the C hook that broke on November 8, 2018" was determined to be an original insulator.[68] Subsequent modeling further suggested that the wear on the C hook whose failure sparked the Camp Fire "was consistent with approximately 97 years of rotational body on body wear."[69] Yet PG&E rarely inspected or patrolled the Caribou-Palermo line: in 2005, "the Caribou-Palermo line was reduced to only being inspected once every five years and patrolled once per year in non-inspection years. ([This was a] reduction . . . from the three patrol/inspections *per year* prior to 1995)."[70] To further cut costs, PG&E "reduc[ed] the thoroughness of the inspections and patrols" that they had already reduced in frequency.[71] As explained in the Butte County District Attorney's public report of the Camp Fire investigation:

62. BUTTE COUNTY DISTRICT ATTORNEY, *The Camp Fire Public Report: A Summary of the Camp Fire Investigation* 2-3, 9 (June 16, 2020) [hereinafter Camp Fire Report].

63. *Id.* at 2-3.

64. *Id.* at 9.

65. Inverse condemnation is in Article 1, section 19 of the California Constitution and has been used against regulated entities since at least 1996. *See, e.g.*, San Diego Gas & Elec. Co. v. Superior Ct. of Orange Cty., 920 P.2d 669, 697-700 (Cal. 1996).

66. Camp Fire Report, *supra* note 62, at 18-19.

67. *Id.* at 19.

68. *Id.*

69. *Id.* at 22.

70. Camp Fire Report, *supra* note 62, at 25 (emphasis added).

71. *Id.* at 27.

> Review of internal PG&E documents, including emails, and interviews with PG&E personnel determined that the unit cost for inspection and patrol is calculated based upon the time that a troubleman spends inspecting an individual structure. . . . [E]ach year PG&E determines an average unit cost for each type of inspection or patrol. The unit cost would be translated into time and multiplied by the total number of structures on an individual line. The result would be the time allotted for the inspection or patrol of that transmission line. . . . salary incentives (bonuses) of Transmission Line Supervisors and Transmission Superintendents was [sic], at least partially, based upon compliance with the inspection and patrol budget. Based upon the evidence, PG&E reduced costs of inspection and patrol by reducing the amount of time budgeted for the inspections and patrols.[72]

Between 2001 and 2018, aerial patrol by helicopter was the primary way by which the Caribou-Palermo lined was inspected and patrolled.[73] Interviews with current and former PG&E employees revealed that prior to 2001, "helicopter patrols of the Caribou-Palermo line [took] one to one and [a] half days."[74] By 2011, however, "flight records document[ed]" a mere "3.2 hours for the aerial patrol of the Caribou-Palermo line,"[75] which did not meet either PG&E's professed internal standards or "the requirements of the law or the regulatory agencies."[76] To make matters worse, in interviews with all qualified company representatives who had "inspected or patrolled the Caribou-Palermo line since [2005]," all denied that they "[had received] any formal training on conducting inspections and patrols and assessing wear."[77] They also denied being provided "with any records (for example tower schematics) specific to the transmission lines being inspected."[78] With all that being the case, it is hardly surprising that PG&E failed to identify the dangerous degree of wear on the C-hook that started the Camp Fire—in spite of the fact

72. *Id.*

73. *Id.* at 40.

74. Camp Fire Report, *supra* note 62, at 40.

75. *Id.*

76. *Id.* at 37. For instance, the alleged regulatory violations include:

> (a) GO 95, Rule 18, for improperly prioritizing a disconnected insulator hold-down anchor; (b) GO 95, Rule 31.1, for failing to maintain equipment for its intended use and regard being given to the conditions under which it was to be operated; (c) GO 95, Rule 31.2, for failing to thoroughly inspect equipment and identify an immediate Safety Hazard or Priority A condition; (d) GO 95, Rule 44.3, for failing to replace or reinforce equipment before its safety factor was reduced to less than twothirds of the safety factor specified in Rule 44.1; (e) GO 165, Section IV, for failing to follow PG&E's internal procedures; (f) Resolution E-4184 for failing to report in a timely manner a reportable incident; and (g) PU Code Section 451 for failing to maintain an effective inspection and maintenance program to identify and correct hazardous conditions on transmission lines in order to furnish and maintain service and facilities.

Joint Motion of Pacific Gas and Electric Company (U 39 E), The Safety and Enforcement Division of the California Public Utilities Commission, Coalition for California Utility Employees, and the Office of Safety Advocate for Approval of the Settlement Agreement at 4, No. I.19-06-015 (Cal. Pub. Utils. Comm'n June 27, 2019).

77. Camp Fire Report, *supra* note 62, at 29.

78. *Id.* While "PG&E documents and management personnel assert[ed] that troublemen receive training on the requirements of the position," it should be noted that the Camp Fire investigation turned up evidence that PG&E records were routinely missing, incomplete, or sometimes falsified. *Id.* at 30, 37-39.

that the transmission tower on which that C-hook was located "had supposedly been assessed *just days before* the fire."[79]

But even if PG&E *had* identified the wear on the C-hook, it is far from clear that PG&E would have acted promptly to rectify the matter. In a series of Wall Street Journal articles following the Camp Fire, the paper reported that PG&E consistently neglected maintenance on its transmission lines, including the Caribou-Palermo line. On February 27, 2019, it reported that in 2013, PG&E told "federal regulators it had planned maintenance work on the line because it sagged too close to the ground and vegetation. It planned to complete the work by February 2016. Instead, it delayed the $30.3 million project several times."[80] Similarly, the Butte County District Attorney dug into PG&E's financial situation, noting that while "[f]inancial records from 2007 through 2018 obtained from PG&E, the CPUC and FERC clearly established PG&E had consistently increased its budget for maintenance, repair and replacement of transmission assets . . . PG&E was not using the money to replace the oldest and most deteriorated transmission assets."[81]

The results of PG&E's criminally negligent actions were catastrophic. In the end, PG&E pled guilty to 84 counts of involuntary manslaughter.[82] The liability associated with the fire also led PG&E to declare bankruptcy in January 2019[83] (PG&E reached a settlement with creditors and emerged from bankruptcy in July 2020).[84]

A public utility being convicted of felonies springing from two separate incidents in under a decade is notable however you look at it.[85] But from a FERC

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79. Order Modifying Conditions of Probation at 9, United States v. Pac. Gas and Elec. Co., No. CR 14-0175 WHA, (N.D. Cal. Apr. 29, 2020) (Doc. 1186) (emphasis in original).

80. Katherine Blunt & Russell Gold, *PG&E Delayed Safety Work on Power Line That is Prime Suspect in California Wildfire*, THE WALL STREET JOURNAL, (Feb. 27, 2019, 1:42 PM), https://www.wsj.com/articles/pg-e-delayed-safety-work-on-power-line-that-is-prime-suspect-in-california-wildfire-11551292977?mod=article_inline.

81. Camp Fire Report, *supra* note 62, at 48.

82. Vanessa Romo, *PG&E Pleads Guilty on 2018 California Camp Fire: 'Our Equipment Started That Fire,'* NPR.ORG (June 16, 2020, 11:09 PM), https://www.npr.org/2020/06/16/879008760/pg-e-pleads-guilty-on-2018-california-camp-fire-our-equipment-started-that-fire.

83. Katherine Blunt & Russell Gold, *PG&E Files for Bankruptcy Following California Wildfires*, THE WALL STREET JOURNAL, (Jan. 29, 2019, 1:06 PM), https://www.wsj.com/articles/pg-e-files-for-bankruptcy-following-california-wildfires-11548750142.

84. Bloomberg, *PG&E Emerges from Bankruptcy*, LOS ANGELES TIMES, (July 1, 2020, 5:29 PM), https://www.latimes.com/business/story/2020-07-01/pge-exits-bankruptcy.

85. PG&E could face further convictions. At the time of this article's publication, PG&E was "being criminally prosecuted in Sonoma County" for its role in the 2019 Kincade Fire, "which Cal Fire blamed on the power company's failure to properly decommission a transmission line near Geyserville that eventually fell in high winds." It was also under criminal investigation for its role in the 2020 Zogg fire, which killed four. *See* Jaxon Van Derbeken, *PG&E Settles With Counties and Cities Over 2019, 2020 Wildfires*, NBCBAYAREA.COM, (last updated May 26, 2021, 9:42 PM), https://www.nbcbayarea.com/investigations/pge-settles-with-counties-and-cities-over-2019-2020-wildfires/2555734/. So far, PG&E has agreed to pay affected local governments "a combined $43.3 million to compensate for starting" the fires. *Id.* On July 18, 2021, PG&E reported that "blown fuses" atop a PG&E utility pole may have started the 2021 Dixie Fire. Adeel Hassan, *The Utility PG&E Says its Equipment May Have Led to a 30,000-acre Wildfire*, THE NEW YORK TIMES, (July 19, 2021), https://www.nytimes.com/2021/07/19/us/pge-dixie-fire.html.

ratemaking perspective, the Camp Fire disaster was particularly revealing. As it happened, the Camp Fire investigations more or less coincided with the litigation of PG&E's "TO18" rate case where PG&E asked FERC for rate relief—including Operations and Maintenance (O&M) spending for the transmission line that failed in the Camp Fire. And discovery and testimony in that case bore out on a large scale what the Wall Street Journal and Butte County District Attorney also found regarding the Caribou-Palermo line. In short, it became clear that each year, PG&E asked FERC for significantly more money in O&M expenses than it ultimately spent.[86]

By the time of PG&E's "TO18" rate case, PG&E had just settled over a decade's worth of rate cases in a row. Parties to those rate cases had seen detailed spending data provided voluntarily by PG&E in settlement negotiations under the auspices of a FERC Administrative Law Judge (ALJ); however, that discovery was all produced subject to settlement confidentiality (and sometimes an additional non-disclosure agreement).[87] Thus, it wasn't until "TO18" was litigated that hearing discovery and testimony was on public view. The testimony showed a consistent pattern of over-forecasting in a way that would increase PG&E's effective profits—for instance, it consistently asked for more O&M money than it spent, and it forecast its gross load to be lower than it was (thus increasing the rates approved by FERC).[88]

In testimony, PG&E offered what it viewed as an explanation for its underspending on O&M:

> In each of these years, PG&E voluntarily agreed to settle on a lower revenue requirement than it had supported in its application (including supporting testimony and workpapers). PG&E typically files in July of the year preceding the [test year] of its TO rate cases. PG&E and the Parties have reached uncontested settlements of the revenue requirement in each of those cases, well before the end of the operating year for which PG&E was seeking funding. Therefore, it is reasonable that PG&E would target its spending, based on an uncontested settlement, when the proposed settlement would grant approval of a revenue requirement lower than as-filed.[89]

86. Summary of Testimony of David Marcus at 25, *Pacific Gas and Elec. Co.*, FERC Docket No. ER16-2320-002 (July 5, 2017) (Revised on Jan. 15, 2018), Ex. SWP-0056, (internal citations omitted) (hereinafter Testimony of David Marcus). "Looking at the multi-year pattern, there have been eight years since 2005 for which PG&E both forecasted a network transmission O&M expense component of its Period II TRR and subsequently reported an actual Period I network transmission O&M expense. In seven out of eight of those years, the network transmission O&M expense component of PG&E's forecasted Period II TRR was higher than the actual network O&M transmission expense subsequently reported. In a ninth year, PG&E has not reported its actual network transmission O&M expenses, but it has reported overall network transmission expenses, which were far below its forecast for that year." *Id.* at 25-26.

87. *See* 18 C.F.R. § 385.602(e) (2021) (preventing the discovery or admission of evidence of settlement offers not ultimately approved by FERC, including comments and discussions thereon).

88. *See* Direct Testimony of David Marcus, *supra* note 86, at 25, 40-42 (internal citations omitted) ("Over the last decade before its TO18 Filing, PG&E had under-forecasted its Period II sales eight times out of ten, including in the five most recent years . . . And indeed, when PG&E has *not* under-forecast its loads, it has faced extraordinary outside circumstances, such as in 2009 when it reasonably failed to predict the recession.").

89. Prepared Rebuttal Testimony of Brian J. Hitson at 3-4, FERC Docket No. ER16-2320-002 (Oct. 9, 2017), Ex. PGE-0040.

By the time of litigation in that case, however, the test year in question had concluded; and PG&E had still underspent on its O&M expenses, despite the fact that it had not settled on a voluntary decrease in rates. Instead, a PG&E witness explained at hearing, PG&E had essentially created a "litigation reserve" anticipating it would not receive its full rate request at hearing:

> A. In the course of this litigation, we've received challenges to our forecasted O&M expenses, and we know at the conclusion of this proceeding, that there may be a refund obligation. And therefore we plan for that event. . . .
> Q. Would there be less O&M performed so there was an amount of dollars available in the event of a refund?
> A. Yes.[90]

This testimony, even in a vacuum, raised concerns that PG&E was submitting an honest O&M budget and then failing to perform necessary maintenance in order to instead earn a higher effective rate of return,[91] enabling PG&E to "enlarge dividends, bonuses, and political contributions."[92] As it turned out, while "fail[ing] to correct problems" that ultimately "sparked deadly wildfires," PG&E spent enormous amounts on campaign contributions and shareholder dividends.[93] Between 2012 and 2017, PG&E issued $5.1 billion in dividends to shareholders.[94] The company spent another $5.3 million on contributions to "political campaigns and candidates," and claimed that this spending was needed to "ensure that the concerns of customers, shareholders, and employees are adequately represented before lawmakers and regulators."[95]

Intervenors in the "TO18" proceeding represented the majority of wholesale customers in California. And the CPUC, which represents the interests of retail customers, was also an active party. None of those entities argued that PG&E should be required to spend its full request on O&M; instead they argued that PG&E's O&M request should be reduced. FERC ultimately agreed, finding:

> Our review of the evidence in the record and the analysis of the Presiding Judge in the Initial Decision shows that PG&E over-forecasted its O&M expense. Additionally, PG&E's practice of holding an amount in reserve for litigation risk, as confirmed by PG&E's witness, further increases the amount by which its O&M expenses are over-forecasted.[96]

FERC then ordered PG&E's rate request reduced by $48 million for the O&M components.[97]

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90. Tr. at 165:10-23 (Kozlowski).

91. Testimony of David Marcus, *supra* note 86, at 54-55. Evidence also adduced in that hearing suggested that PG&E was, in fact, earning a higher effective rate of return than would normally be authorized by FERC. *Id.*

92. Order Modifying Conditions of Probation, *supra* note 58, at 1.

93. Nicholas Iovino, *PG&E Defends Spending on Investors, Politicians as Fires Sparked*, COURTHOUSE NEWS SERVICE (July 31, 2019), https://www.courthousenews.com/pge-defends-spending-on-investors-politicians-as-fires-sparked/.

94. *Id.*

95. *Id.*

96. Opinion No. 572, *Pac. Gas. & Elec. Co.*, 173 FERC ¶ 61,045 at P 215 (2020) (internal citations omitted).

97. *Id.*

As such, PG&E's consequence for over-forecasting its O&M spending in previous rate cases was a natural one—it received less money to spend on O&M in the "TO18" period.[98] In many ways, this is the rate setting process working as it should. However, when a utility is not fulfilling its basic maintenance obligations, granting it less money for maintenance makes it even *more* likely to skimp going forward to some degree. Without oversight or intervention, FERC may be unwittingly risking throwing the company into a downward spiral.

Meanwhile, the PG&E story continues. During the 2019 fire season, PG&E de-energized power to large portions of its system during high-fire risk conditions,[99] which might well have spared Californians another catastrophic wildfire.[100] Even so, it also meant that millions of Californians were without power for significant amounts of time.[101] While acknowledging that PG&E deserved credit for taking that step, PG&E's probation judge—Judge Alsup—noted that the conditions that necessitated it "remain proof positive of how unsafe PG&E had allowed its maintenance backlog to become."[102] In a scathing order, Judge Alsup laid out what he viewed as PG&E's failures to fulfill its obligations as a public utility:

> A fundamental concern in this criminal probation remains the fact that Pacific Gas & Electric Company, though the single largest privately-owned utility in America, cannot safely deliver power to California. This failure is upon us because for years, in order to enlarge dividends, bonuses, and political contributions, PG&E cheated on maintenance of its grid—to the point that the grid became unsafe to operate during our annual high winds, so unsafe that the grid itself failed and ignited many catastrophic wildfires.[103]

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98. *Id.*

99. Order Modifying Conditions of Probation, *supra* note 58, at 4. As PG&E's probation judge noted "[A]fter each [power shut-off], crews discovered, in total, 365 fallen limbs and trees strewn across PG&E distribution lines. Even according to PG&E, 291 of those fallen limbs and trees would've likely caused arcing, meaning that sparks and molten metal flashed upon the dry grass or whatever lay below." *Id.* at 5 (internal citations omitted).

100. How much credit PG&E should receive for this de-energization is up for debate. At the end of the day, it only came about after PG&E's probation judge "strongly urged" PG&E to "temporarily de-energize any power line unsafe to operate during dry-season windstorms." PG&E "protested the idea and resisted any order to engage in such temporary de-energizations;" ultimately, however, it "voluntarily" de-energized portions of its system. Order Modifying Conditions of Probation at 3-4, U.S. v. Pac. Gas & Elec. Co., No. 3:14-cr-00175-WHA (N.D. Cal. Apr. 29, 2020), ECF No. 1186.

101. *See, e.g.*, Olga R. Rodriguez & Janie Har, *Millions Face Power Outages in Northern, Central California*, DENVER POST (Oct. 9, 2019), https://www.denverpost.com/2019/10/09/california-power-outages/ ("The utility announced that it was shutting off power to 800,000 customers . . . It could take as many as five days to restore power after the danger has passed"); ASSOCIATED PRESS, *millions remain without power in northern california as fires spread*, KPBS (Oct. 28, 2019), https://www.kpbs.org/news/2019/oct/28/fires-spread-amid-power-outages-northern-californi/ ("Pacific Gas & Electric Co. has notified more than 1.2 million people that they may have their electricity shut off for what could be the third time in a week and the fourth time this month."). Since then, PG&E has unveiled an ambitious decade-long plan to place 10,000 miles of its most risk-prone lines underground at a cost ranging from $15 to $40 billion. *See* Ivan Pen, *PG&E Aims to Curb Wildfire Risk by Burying Many Power Lines*, N.Y. TIMES (Aug. 6, 2021), https://www.nytimes.com/2021/06/24/us/politics/what-is-in-the-infrastructure-plan.html.

102. *PG&E*, No. 3:14-cr-00175-WHA, at 4.

103. *Id.* at 1.

To be sure, PG&E is an extreme example of the consequences that can result when utilities cut corners in order to maximize their profits. In all likelihood, the Tennessee and West Virginia American Water Company cases are more reflective of the "average" impact of such corner cutting. Nevertheless, the point remains that if utilities have a perverse incentive to maximize profits by reducing spending in other areas, such as system maintenance, basic economic theory suggests that some utilities will choose to do so. Every time that occurs, ratepayers suffer some degree of harm—whether that be a reduction in reliability or, in the worst cases, significant harm to public safety. Ultimately, the more often corners are cut, the likelier it is that sooner or later another system will fail catastrophically. And while few failures are as catastrophic as the Camp Fire, utility failures on a lesser scale may still be enormously disruptive to life and livelihood. Protecting customers from devastating service failures is a core component of being a state or federal regulator. However, what can FERC do when its typical response—reducing the money a utility receives as a consequence for over-forecasting O&M expenses—risks exacerbating the utility's perverse incentive to cut costs?

III. FERC ENFORCEMENT, IN GENERAL, AND RELIABILITY STANDARDS SPECIFICALLY, ARE NOT DESIGNED TO ADDRESS THE INCENTIVES ASSOCIATED WITH TRADITIONAL RATEMAKING.

When thinking about how to address inappropriate utility cost-cutting, it may seem self-evident to approach it as a service quality issue and, perhaps, prescribe and enforce minimum service standards. After all, most jurisdictions empower utility commissions to "investigat[e] and issue findings on whether the service offered under their jurisdiction is 'unjust, unsafe, improper, inadequate or insufficient,' and to promulgate rules for its improvement."[104] At the state level, minimum performance is ensured through regulations referred to generally as "quality standards."[105] However, the FPA does not give FERC similar authority, at least explicitly, to enforce general service quality standards at the federal level.[106]

Mandatory reliability standards, the focus of the remainder of this section, are only a subset of service quality, but come the closest to providing objective criteria. However, these standards were never designed to police utility maintenance budgets or address individual utility performance issues that do not implicate the reliability of the larger grid.

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104. KAHN, *supra* note 6, at 21.

105. *Id.*

106. We acknowledge that section 207 of the FPA, 16 U.S.C. § 824f, states that upon a complaint by a state commission, ''[w]henever the Commission . . . shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation . . . ." However, FERC has only invoked that authority once since the FPA was enacted in 1935. *See District of Columbia Pub. Serv. Comm'n*, 114 FERC ¶ 61,017 at PP 28-31 (2006) (ordering PJM Interconnection, L.L.C. and Potomac Electric Power Company to file a transmission plan to provide adequate reliability to the Washington D.C. area). There, the Department of Energy had already used its FPA section 202 emergency powers to order the Mirant Potomac River plant, which had threatened to shut down, to continue generating electricity. *Id*. at P 1.

Mandatory reliability standards originated with the Energy Policy Act of 2005 and were incorporated in section 215 of the FPA,[107] which made FERC responsible for the reliable operation of the interconnected electric grid, and greatly expanded its role and jurisdiction in that area. Where FERC "had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[108] FERC now had the authority to certify and oversee the ERO; the organization charged with developing[109] and enforcing the mandatory reliability standards[110] against users, owners, and operators of the bulk power system.

In 2006, FERC used its FPA section 215 authority to certify NERC as the ERO.[111] Like regional transmission organizations (RTOs) or independent system operators (ISOs), NERC is a non-governmental agency. Today, through six regional entities, it enforces over one hundred reliability standards meant to "provide for an adequate level of reliability of the bulk-power system."[112]

NERC's Reliability Standards undoubtedly serve a critical purpose, but they were not designed for the task of ensuring minimum performance of individual utilities. Instead, FPA section 215 mandates that FERC (and as certified by FERC, NERC) protect against "instability," "uncontrolled separation," and "cascading failures."[113] As reflected in the statute's language, Congress was concerned with "reliable operation of the bulk-power system"[114] and focused regulation of its individual elements only to the "extent necessary to provide for reliable operation of the bulk-power system."[115]

The FPA has drawn jurisdictional lines between state and federal regulation of electricity. As mentioned above, FPA section 215 provides for federal jurisdiction only to the extent necessary to provide for reliable operation of the bulk electric system.[116] While there has been controversy over the years about how far down the chain this extends, as a general rule, FERC and NERC have not promulgated standards over every transmission facility that is included in FERC-jurisdictional transmission rates. For instance, NERC's Vegetation Management

107. 16 U.S.C. § 824o (added by Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 594, 941-46).

108. FERC, RELIABILITY PRIMER 5 (2020), https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

109. FERC cannot directly issue Reliability Standards; it can only direct NERC to do so, and either approve the standards as proposed or remand them to NERC. *See* 16 U.S.C. § 824o(d).

110. *See Id.* at § 824o(e). Though FERC has delegated its enforcement authority to the ERO (*i.e.*, NERC), FERC retains the ability to directly enforce reliability standards and may review any penalty assessed by NERC.

111. Order No. 672, *North Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at PP 1, 3 (2006).

112. 16 U.S.C. § 824o(c)(1).

113. *Id*. at § 824o(a)(3).

114. *Id*.

115. *Id*.

116. 16 U.S.C. § 824(a)-(b) (2012) (specifying that the Act provides for federal jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce" but not "over facilities used for the generation of electric energy or over facilities used in local distribution").

Standard[117] does not apply to all FERC jurisdictional transmission lines; those minimum clearance requirements generally only apply to lines operating above 200 kV.[118] The reliability standard, titled "Transmission Maintenance" (FAC-501-WECC-2), only applies to lines along major transfer paths identified by Western Electric Coordinating Council (WECC), a NERC regional entity.[119]

Even where maintenance standards apply, the requirements are written to afford utilities considerable flexibility in planning and executing needed maintenance, to say nothing of the amount management may spend. For example, FAC-501-WECC-2 requires that the utility develop and maintain a transmission maintenance and inspection plan containing certain elements (*e.g.*, list of facilities, maintenance methodology, periodicity, etc.), but leaves its design and execution largely up to the utility.[120] The utility's maintenance plan may be "performance-based," "time based," "condition based," or some combination thereof.[121] The utility must comply with its own plan and update it annually—maintenance budgets are not discussed at all.

The standards are tailored to address the risks to the grid that animate FPA section 215's statutory purpose, but also highlight the practical challenges of a more granular, prescriptive approach. For instance, NERC has not tried to set detailed, comprehensive standards that ensure utilities—each with its own unique equipment, configuration and circumstances—are performing O&M on a sustainable cycle.

Nor are we arguing that it should. Such a top-down approach would be an enormous undertaking, particularly in light of the lengthy, stakeholder driven process NERC uses to develop standards. Requiring NERC to come up with detailed standards to ensure that every aspect of utility maintenance is performed properly, regardless of how attenuated its impact would be on the overall grid, depends on a fairly broad view of the authority granted to FERC/NERC under FPA section 215. Even assuming it could be done, ensuring NERC and FERC have the enforcement capability needed to oversee those standards would require a drastic expansion of their scope and, undoubtedly, their funding.

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117. N. AM. ELEC. RELIABILITY CORP., STANDARD NO. FAC-003-4, TRANSMISSION VEGETATION MANAGEMENT 1 (2016), https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=FAC-003-4&title=Transmission%20Vegetation%20Management&Jurisdiction=United%20States.

118. This is why it is believed the power lines involved in the PG&E fires have not been found to be subject to FERC's jurisdiction. RICHARD J. CAMPBELL, CONG. RSCH. SERV., IN11189, CALIFORNIA WILDFIRES AND BULK ELECTRIC SYSTEM RELIABILITY 2 (2019) (noting that NERC's vegetation clearance requirements apply to overhead transmission lines operating above 200 kV, and some that operated below 200 kV, if those lines are designated by the Western Electric Coordinating Council (a NERC regional entity); however, distribution lines, usually 100 kV, are regulated by state utility regulatory commissions).

119. N. AM. ELEC. RELIABILITY CORP., STANDARD NO. FAC-501-WECC-2, TRANSMISSION MAINTENANCE 1 (2018), https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=FAC-501-WECC-2&title=Transmission%20Maintenance&Jurisdiction=United%20States (limiting application of the standards to the WECC paths listed in Attachment B).

120. *Id.*

121. *Id.*

This is not to say that FERC is the wrong entity to address this problem. To the contrary, FERC is the agency empowered to review transmission rates and, thus, is the only entity that can address a mismatch between the rate charged and the service provided. As will be discussed in the following section, FERC already has the tools to do that under existing law.

IV. FERC SHOULD TAKE ADVANTAGE OF EXISTING TOOLS TO ENSURE THAT AUTHORIZED RATES HELP MAINTAIN, RATHER THAN WORK AGAINST, SERVICE QUALITY.

As was discussed in Part I, FERC has an obligation under section 205 of the Federal Power Act to ensure that rates under its jurisdiction are just and reasonable. As noted there, the reasonableness of a rate—literally, the price of service—cannot be judged in a vacuum, as "[p]rice really has no meaning except in terms of an assumed quality of service."[122] Thus, FERC should think of its jurisdiction as encompassing more than just setting rates at a theoretically appropriate numerical level. Ensuring that customers are getting the safe and reliable service that they pay for is just as core of a component of FERC's ratemaking responsibility. In fact, FERC already has an array of ratemaking tools at its disposal that it could use to more rigorously ensure that (1) utilities are not increasing their profits by inappropriately reducing operating costs and (2) that authorized rates are used to maintain safe and reliable service. Though the fundamentals of ratemaking (ROE methodology aside) tend to remain fairly static, FERC is "not bound to the use of any single formula or combination of formulae in determining rates."[123] Instead, "[u]nder the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling."[124] In other words, FERC and other utility commissions have a variety of tools at their disposal to address service and reliability issues.

One option that can change the incentives for utilities, often for the better from a customer standpoint, is transitioning from a stated rate to a formula rate (in which estimated costs and sales are trued up to actuals through operation of the formula).[125] For example, PG&E transitioned to a formula rate in 2018 upon filing

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122. KAHN, *supra* note 6, at 21; *see also Am. Tel. & Tel. Co.*, 524 U.S. at 215 ("Since rates have meaning only when one knows the services to which they are attached, any claim for excessive rates can be couched as a claim for inadequate services and vice versa.").

123. Wisconsin v. Fed. Power Comm'n, 373 U.S. 294, 309 (1963) (quoting Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 602 (1944)); *see also* Fed. Power Comm'n v. Nat. Gas Pipeline Co., 315 U.S. 575, 586 (1942) ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas.").

124. *Fed. Power Comm'n*, 373 U.S. at 309 (quoting *Hope Nat. Gas Co.*, 320 U.S. at 602).

125. A formula rate is a cost-of-service ratemaking method in which "pre-specified formulas" are used "to calculate automatic rate adjustments to keep the utility's actual rate of return on equity (ROE) within or near a specified band around the authorized ROE." LAURENCE D. KIRSCH ET AL., ALTERNATIVE ELECTRICITY RATEMAKING MECHANISMS ADOPTED BY OTHER STATES, at v (2016) (emphasis removed); *see also* KEN COSTELLO, NRRI BRIEFING PAPER NO. 10-11, FORMULA RATE PLANS: DO THEY PROMOTE THE PUBLIC INTEREST?, at ii (2010) ("[T]he utility adjusts its base rates outside of a general rate case, usually annually, based on an actual or projected rate of return (ROR) on rate base or equity . . . .") (emphasis removed).

its "TO20" rate case, and this has been the trend for many other utilities as well. For instance, PG&E's peers in California (the Southern California Edison Company (SCE) and San Diego Gas and Electric) also made that transition over the last decade.[126] Under a formula rate, utilities cannot increase their effective rate of return by underspending on items like O&M; instead, their rate of return is a fixed component in the formula. For this reason, they are sometimes preferred by ratepayers and their advocates, who have spent years fighting with utilities about over-forecasting in stated rates. However, they are not universally preferred by customers or ratepayer advocates, who sometimes believe that the formula can leave components, such as ROE, in place after they are no longer just and reasonable since the burden of filing a complaint rests on the customer. Some also believe that the utility has more control in a formula rate review process, which is relatively opaque, where customers are dependent on an "annual update" process each year to review the inputs and true-ups. At the end of the day, formula rates have a tendency to shift financial risks from utilities to customers.[127]

Further, formula rates are not devoid of perverse incentives for utilities. Customers may worry that utilities will spend unnecessarily, knowing they are virtually sure of recovering that money.[128] While utilities with formula rates may have less reason to skimp on maintenance, they might also have less incentive to control costs than they would under a stated rate, and, because their rates adjust automatically, there is arguably less regulatory review of the prudence of these costs.[129]

These are all real concerns. That said, that formula rates reduce the incentives for utilities to skimp on maintenance should not be ignored either and should be considered as part of the calculus when a stated rate utility seeks to transition to a formula rate. All the same, formula rates in and of themselves should not be considered a panacea. In the following section, we discuss a number of other options that FERC can employ with fewer potential downsides for consumers—some of which may sometimes be appropriate in the formula rate context as well.

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126. *See, e.g.*, Appendix X Formula Rate Tariff Filing, *San Diego Gas & Elec. Co.*, FERC Docket No. ER21-243-000, at 2 (Oct. 29, 2020); Paul Dumias, *Southern California Edison Requests Changes to Transmission Formula Rate for Wildfire Risk*, ENERGY CENT. (Apr. 16, 2019), https://energycentral.com/c/tr/southern-california-edison-requests-changes-transmission-formula-rate-wildfire. It should be noted, however, that FERC has always left it up to utilities whether to file a stated or formula rate. While FERC could probably use its authority to mandate specific rate structures, the approaches we suggest are more targeted, and meant to preserve management discretion.

127. KIRSCH ET AL., *supra* note 125, at 10; KEN COSTELLO, NRRI REPORT NO. 14-03, ALTERNATIVE RATE MECHANISMS AND THEIR COMPATIBILITY WITH STATE UTILITY COMMISSION OBJECTIVES 39 (2014).

128. *See, e.g.*, ELEC. CONSUMERS RES. COUNCIL, FORMULA RATES, https://elcon.org/formula-rates/ (identifying as problematic the "reduced incentives to control costs" and "reduced scrutiny and transparency" associated with formula rates).

129. KIRSCH ET AL., *supra* note 125, at 10-11; COSTELLO, *supra* note 127, 38 n.106 ("[A] formula rate place could increase the chances of a utility passing through imprudent cost to customers.").

A. FERC Could Account for Utility Malfeasance in Evaluating Utility Riskiness and Setting ROEs

As a general matter, the costs of remediating maintenance failures—and certainly penalties resulting from those failures—should come from shareholder profits, not from ratepayers. Commissions, including FERC, must be vigilant about this; it sometimes means a close examination of a utility's capital costs to ensure it is not covertly recovering the cost of a penalty.

Specifically, the question of how utility malfeasance weighs into the determination of ROEs has not been sufficiently considered. FERC is obligated under *Hope* and *Bluefield* to ensure that utilities earn ROEs "commensurate with returns on investments in other enterprises having corresponding risks."[130] How FERC determines the risk of a given utility has changed over the years as it has revised its ROE analyses. In general, it involves an examination of a utility's credit ratings and ability to attract capital and comparisons to utilities deemed "proxies."[131] However, this analysis fails to account for the fact that a utility's excess risk may, in some cases, be largely of its own creation.

For instance, just one year after the Camp Fire, PG&E asked the CPUC for a significant rate hike, arguing that its ROE should be raised "from the current 10.25 percent to 16 percent."[132] PG&E justified this increase as necessary to allow it to "invest billions in wildfire safety and system reliability"[133] and "to give investors a higher return to lure capital," given the "utility's financial woes."[134] In recent FERC rate cases, PG&E has likewise asked for a higher ROE than comparable utilities located outside of California, arguing that it is riskier than other utilities due to its wildfire risk.[135]

Some of this risk—particularly prior to the 2019 passage of legislation in California creating a joint liability fund[136]—is due to California's particular inverse condemnation system, mentioned in Part I, under which utilities can be liable for damages for fires started with their equipment even when those fires were not negligently caused.[137] Other California utilities, such as SCE, have also pointed to this in their FERC and CPUC filings.[138]

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130. *Hope Nat. Gas Co.*, 320 U.S. at 603.

131. *Maine*, 854 F.3d at 20-21.

132. Dale Kasler, *Gavin Newsome blasts PG&E's request to raise rates and profits as debate over wildfire costs rages*, SACRAMENTO BEE (Apr. 23, 2019), https://www.sacbee.com/news/politics-government/capitol-alert/article229556149.html.

133. *Id.*

134. *Id*.

135. *See, e.g.*, Initial Brief on Paper Hearing Concerning Return on Equity, *Pac. Gas & Elec. Co.,* FERC Docket No. ER16-2320-002, at 1, 9-10 (Dec. 14, 2020).

136. Ivan Penn & Peter Eavis, *California Lawmakers Give Utilities a Backstop on Wildfire Liability*, N.Y. TIMES (July 11, 2019), https://www.nytimes.com/2019/07/11/business/energy-environment/wildfire-california-utilities.html.

137. *Id.*

138. *See, e.g.*, Transmission Owner Tariff Transmission Rate Filing (TO2019A), *Southern Cal. Edison Co.,* FERC Docket No. ER19-1553-0000, at 5, 17, 20 (Apr. 11, 2019); CAL. PUB. UTIL. COMM'N, PROCEEDINGS A1904014, APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U338-E) FOR AUTHORITY TO

But neither PG&E's elevated risk level, nor its particular "financial woes," are equally shared by all California utilities. PG&E's 2019 bankruptcy[139]—the "biggest utility bankruptcy in U.S. history"[140]—was declared while the company anticipated incurring enormous amounts of liability *because its negligently-maintained equipment sparked the "single most destructive wildfire in California history and the worst in the United States in a century."*[141] Thus, PG&E's elevated risk level is unique even among California utilities, and its risk level and "financial woes" are, at least in this instance, entirely self-inflicted. As of press time, the issue of how PG&E's risk should factor in determining PG&E's ROE has been briefed before FERC in PG&E's "TO18" rate case.[142] This case could be an opportunity for FERC to make it clear that it will not grant an ROE premium to a utility on the grounds that it is an unusually risky investment *when its own bad behavior is the reason it is a risky investment in the first place*.[143]

The law is clear that there is a "zone of reasonableness [that] creates a broad range of potentially lawful ROEs" (as opposed to a single just and reasonable ROE).[144] To that end, it is clear that FERC has the authority to refrain from rewarding utility malfeasance with higher ROEs. As one FERC ALJ put it, "efficient management is assumed in setting a rate of return."[145] And indeed, in the natural gas context, FERC has been more explicit and has long held that it will not "reward" a utility for inefficiencies that put it at risk.[146] That logic applies equally to electric utilities.[147] Allowing bad actors to profit at the consumers' expense is

ESTABLISH ITS AUTHORIZED COST OF CAPITAL FOR UTILITY OPERATIONS FOR 2020 AND TO PARTIALLY RESET THE ANNUAL COST OF CAPITAL ADJUSTMENT MECHANISM 3 (2019).

139. Katherine Blunt & Russell Gold, *PG&E Files for Bankruptcy Protection Following California Wildfires*, WALL STREET J. (Jan. 29, 2019), https://www.wsj.com/articles/pg-e-files-for-bankruptcy-following-california-wildfires-11548750142?mod=article_inline.

140. Bloomberg, *PG&E Emerges from Bankruptcy*, L.A. TIMES (July 1, 2020), https://www.latimes.com/business/story/2020-07-01/pge-exits-bankruptcy.

141. Kirk Siegler, *The Camp Fire Destroyed 11,000 Homes. A Year Later Only 11 Have Been Rebuilt*, NAT'L PUB. RADIO (Nov. 9, 2019), https://www.npr.org/2019/11/09/777801169/the-camp-fire-destroyed-11-000-homes-a-year-later-only-11-have-been-rebuilt (emphasis added).

142. *See, e.g.*, *Pac. Gas & Elec. Co.*, FERC Docket No. ER16-2320-002 (Dec. 14, 2020). Note that although the Camp Fire postdates the period under consideration in the "TO18" rate case, the 2017 wine country fires happened right in the middle of it. And as seen, the maintenance failures were ongoing. *See Pac. Gas & Elec. Co.*, *supra* note 135, at 7, 10; Bill Gabbert, *A list of some of the fires attributed to PG&E powerline equipment*, WILDFIRE TODAY (Apr. 6, 2021), https://wildfiretoday.com/2021/04/06/a-list-of-some-of-the-fires-attributed-to-pge-powerline-equipment/.

143. *Maine*, 854 F.3d at 27-28, 30.

144. *Id.* at 23, 26.

145. *Cities of Greenwood & Seneca, S.C. v. Duke Power Co.*, 77 FERC ¶ 63,017, at p. 65,077 (1996) (citing Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692-93 (1923) ("[T]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, *under efficient and economical managements*, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.")) (emphasis added).

146. *Transcon. Gas Pipe Line Corp.*, 85 FERC ¶ 61,323, at pp. 62,270-72 (1998) ("when a pipeline's higher risk is due to its own inefficiencies, FERC will not increase its ROE.").

147. *Northern Nat. Gas Co.*, 175 FERC ¶ 61,059 (2021) (Danly, Comm'r, dissenting at P 1 n.2)

unjust, unreasonable, and contrary to the duty of regulatory agencies charged with protecting the consumer interest. It also provides utilities with little financial incentive to ensure they properly maintain their systems.

B. FERC Could Make Greater Use of the "Prudent Investment" Standard

The "prudent investment" standard—under which a utility need only be "provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility's outlays"[148]—has been a long-standing part of utility ratemaking. The prudent investment standard requires:

> '[A] utility [to] demonstrate that it went through a reasonable decision making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner.' Further . . . a utility is compensated for all prudent investments at their cost when made, irrespective of whether they are deemed necessary or beneficial in hindsight. That is, the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time . . . . Finally, the inquiry encompasses a public utility's continuation of an investment as well as its decision to enter into that investment, and requires the utility to respond prudently to changing circumstances or new challenges that arise as a project progresses.[149]

The flip side of that is that a utility commission need not—and in fact, should not—allow recovery of *imprudently* incurred costs.

Prudence challenges are often discussed as a way to curb utility "gold plating"—circumstances where utilities upgrade their system unnecessarily. But they can also be employed when utilities fail to do maintenance year after year, and then must over-spend to address a backlog or remediate a disaster. They might also prove useful where utilities are doing the *wrong* work—for instance, where they are overspending on capital projects on which they earn a return and underspending on bread-and-butter maintenance to keep the system running. For this reason, they are a useful tool in the arsenal of ensuring reliability. Unfortunately, as a practical matter, this tool has slipped into obsolescence at FERC.

To that end, there are only rare examples of successful prudence challenges at FERC. For instance, in *Public Service Company of New Hampshire,*[150] the Public Service Company of New Hampshire (PSNH) was found to have acted imprudently when it "made spot purchases of coal from [suppliers other than its main supplier] for the purpose of bringing its coal reserve up to 45 days supply."[151]

("[T]he courts have treated the [Natural Gas Act (NGA)] and FPA as analogous in substance.). *See Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (following its "established practice of citing interchangeably decisions interpreting the pertinent sections of the [FPA and NGA]" due to the relevant provisions being "'substantially identical'" (citations omitted)).

148. KARL MCDERMOTT, COST OF SERVICE REGULATION IN THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY: A HISTORY OF ADAPTATION 6, 9 (2012).

149. Gulf States Utils. Co. v. La. Pub. Serv. Comm'n, 578 So. 2d 71, 84-85 (La. 1991) (internal citations omitted).

150. 1 FERC ¶ 63,039, at pp. 65,297-98 (1977).

151. *Id.* at 65,296-97.

PSNH made these spot purchases at times when (1) *force majeure* prevented its main supplier from providing the full shipment *and* (2) its reserves were low (meaning it had less than a 45 day supply).[152] However, FERC noted that, under PSNH's contract, the main supplier was obligated to make up delayed shipments—even if the delay were caused by a *force majeure* event—should the delay cause PSNH's reserve level to fall below a 45 day supply.[153] The contract further made it clear that "PSNH had the right to call upon [the main supplier] to ship additional carloads of coal, regardless of whether the reserve pile had fallen below 45 days."[154] FERC thus held that

> the cost of spot purchases were imprudent and unreasonable to the extent the total of these costs exceeded the total price (including freight) which would have been paid . . . [the main supplier] for coal had it been delivered by . . . [the supplier] under the contract with PSNH instead of the coal obtained by spot purchases.[155]

It thus required PSNH to refund its jurisdictional customers.[156] That case, however, was an interesting anomaly and FERC's long-standing presumption that costs are prudent unless shown otherwise has generally not been successfully rebutted.[157] It is, of course, not the role of a regulator to second guess the day-to-day decision-making of utility management.[158] As FERC has held, "managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers."[159] But perhaps due to this underlying doctrine, the outcome is that prudence challenges have succeeded so rarely at FERC that they are rarely attempted and are generally discussed among practitioners as a futile endeavor.

For example, in *Williston Basin Interstate Pipeline Company*,[160] FERC applied the prudence doctrine to a pipeline's capital costs. In *Williston*, several state agencies challenged the Williston Basin Interstate Pipeline's proposed cost of long-term debt. Pursuant to FERC's general policy, the appropriate cost of long-term debt should be determined based on data acquired during a test period.[161] Williston proposed a cost of long-term debt of 10.24 percent; in response, the state

152. *Id.*

153. *Id.* at 65,297.

154. 1 FERC ¶ 63,039, at 65,297.

155. *Id.* at 65,298.

156. *Id.*

157. Richard J. Pierce, Jr., *Public Utility Regulatory Takings: Should the Judiciary Attempt to Police the Political Institutions?,* 77 GEO. L.J. 2031, 2050 (1989) ("When I researched this topic for other purposes in 1983, I conducted an exhaustive search for regulatory disallowances based on imprudence. The Federal Energy Regulatory Commission (FERC) and its predecessor, FPC, had never disallowed an investment on the basis of imprudence in the agency's fifty year history. I could find only a few cases in which state agencies had disallowed investments based on a finding of managerial imprudence. Even in those rare cases—about one per decade—the magnitude of the disallowance was relatively trivial."); *See also* MELISSA WHITED ET AL., UTILITY PERFORMANCE INCENTIVE MECHANISMS: A HANDBOOK FOR REGULATORS 12 (2015).

158. KARL MCDERMOTT, COST OF SERVICE REGULATION IN THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY, A HISTORY OF ADAPTATION 12-13 (2012).

159. *New England Power Co*., 31 FERC ¶ 61,047 (1985) (emphasis added).

160. 72 FERC ¶ 61,074 (1995) [hereinafter *Williston*].

161. *Id.* at 61,373.

agencies argued "that the cost of Williston's long-term debt should be reduced to 8 percent because it should have refinanced its debt in 1992 down to that level."[162] Instead, Williston refinanced and lowered its debt costs in 1993, after the test period concluded, at which point those lower costs would not affect its rate case.[163] FERC analyzed the facts under the prudence standard but ultimately sided with the pipeline. Finding that "even if Williston [had refinanced] during the test period of this case, it only could have gotten down to a 9.85 percent rate,"[164] FERC concluded that the difference between a 10.24 percent rate and a 9.85 percent rate was "not so significant as to demonstrate imprudence in failing to renegotiate the debt at that time, rather than a later, as it did."[165]

It is noteworthy that the cases mentioned above are quite old. For whatever reason—perhaps because practitioners have long viewed FERC as resistant to prudence challenges, combined with general trends towards higher numbers of settlements—relatively few have actually been litigated at FERC in recent years. PG&E's "TO18" litigation, once again, provides a rare example. In that case, the CPUC challenged the prudence of PG&E's Embarcadero-Potrero project—a transmission project that PG&E had told the CPUC would cost some $196.8 million when it sought a Certificate of Public Convenience and Necessity. PG&E then proceeded to file at FERC for recovery of $288.3 million.[166]

The CPUC alleged a number of errors, including that:

> [T]he complexity and magnitude of the Embarcadero-Potrero cable warranted a longer time line than PG&E prescribed for the project; PG&E embarked on a "high-risk" execution strategy simultaneously conducting design, permitting and procurement; during the planning, permitting and most of the design phase, PG&E assigned a single project manager who was also managing two other projects; the project experienced an unspecified "governance" problem in 2013, as well as inadequate schedule development, and difficulties in effectively managing several large engineering, procurement and construction contracts; and PG&E effectively chose to act as the prime contractor without understanding the associated responsibilities and risks.[167]

While this seems like a daunting litany of complaints, the ALJ who issued an initial decision in the case dismissed them in two paragraphs, and FERC concurred. In fact, the ALJ concluded, if that were

> sufficient to raise serious doubts as to the prudency of PG&E's expenditures, then any utility that undertakes an expensive, complex, unfamiliar project can expect to have to prove the prudency of large portions of its project expenditures. Any reasonable utility manager would thus think twice about undertaking such a project, at least

162. *Id.*

163. *Id*.

164. 72 FERC ¶ 61,074, at 61,374.

165. *Id.*

166. In "TO18", the CPUC brought an additional prudence claim related to PG&E transmission projects which did not go through the ISO transmission planning process. FERC also dismissed this claim. However, the legal arguments involved in that claim were complicated and related to a separate complaint filed by a number of entities (including the CPUC) against PG&E on its transmission planning standards and FERC Order No. 890, so we do not discuss it here as a representative example. *Pac. Gas and Elec. Co.*, 175 FERC ¶ 61,040 at P 632 (2021).

167. *Id.* at P 642.

> if it were avoidable. Yet the optimal efficiency of the electric transmission grid depends upon utilities' willingness to undertake just such projects.[168]

Without weighing in on the merits of that case, it does seem noteworthy that even a state regulator raising the issue of an overrun of nearly 50% and not far short of $100 million did not raise many eyebrows at FERC. Combined with the rarity of such challenges, this appears to support the common assumption held by practitioners that prudence challenges are simply not a route to success at FERC. But that means that FERC is essentially making a tool unavailable that could allow it to incentivize utilities to spend money in ways that helps ensure service quality.

A rulemaking or even a policy statement[169] by FERC announcing a closer look at prudence issues could alter the prudence standard such that it becomes a real option for customers looking at how their jurisdictional utilities spend money. This does not need to supplant any state oversight or utility management prerogatives. Instead, it would ensure that when there is long-standing evidence that utilities have neglected maintenance for years leading to more expensive maintenance later on, ratepayers could object. Likewise, if utilities are performing less necessary capital work on which they earn a return rather than maintenance work on which they don't, ratepayers again would have recourse. None of this would necessarily be used often—but the existence of the option could have an incentive effect in and of itself.

It is also worth noting that a challenge of this type will never be cheap or easy to mount. It is likely to require a significant investment in discovery and engineering witnesses or experts to even be credible. For those who are concerned about the expanded scope of prudence challenges, this should be of some comfort.

C. FERC Could Use its FPA § 219 Authority to Implement Performance-Based Ratemaking.

Section 219 of the FPA—added to the statute in 2005—enabled, and indeed in some cases mandated, that FERC implement "incentive-based (including performance-based) rate treatments"[170] for a variety of behaviors (e.g., joining a RTO/ISO). Rate incentives quickly became a much used, often-litigated tool in FERC's arsenal. The same cannot be said for PBR. Though FERC understood FPA § 219 "to require the Commission to consider [PBR] as an option among

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168. *Id.* at P 643.

169. As explained in *Pac. Gas & Elec. Co. v. Federal Power Comm'n*, 506 F.2d 33, 38 (D.C. Cir. 1974), "[a]n agency may establish binding policy through rulemaking procedures by which it promulgates substantive rules . . . The critical distinction between a substantive rule and a general statement of policy is the different practical effect that these two types of pronouncements have in subsequent administrative proceedings. A properly adopted substantive rule establishes a standard of conduct which has the force of law. . . . A general statement of policy, on the other hand, does not establish a 'binding norm.' . . . The agency cannot apply or rely upon a general statement of policy as law because a general statement of policy only announces what the agency seeks to establish as policy. . . . When the agency applies the policy in a particular situation, it must be prepared to support the policy just as if the policy statement had never been issued."

170. 16 U.S.C. § 824 (2005).

incentive ratemaking treatments,"[171] it declined to adopt PBR measures when promulgating Order 679 (which implemented FPA section 219), concluding that doing so would be "premature."[172] In declining, however, FERC did not foreclose the possibility of adopting PBR at a later time.[173] In fact, FERC held a technical workshop to discuss certain PBR approaches in September 2021.[174]

For the most part, PBR emerged as an idea at FERC[175] in the early 1990s, precisely because it was intended to help address some of the issues raised in this article—namely, that under traditional ratemaking "utilities face few explicit rewards for taking risks to cut their costs aggressively, and few penalties for excessive spending."[176] Accordingly, traditional ratemaking mechanisms arguably do not "foster long-run productive efficiency."[177] PBR, in contrast, is meant to "create links between regulated utility financial rewards (or penalties) and desired outcomes."[178] In other words, under PBR, a utility might receive a financial reward for producing a desired outcome (i.e., meeting or beating a performance target); similarly, it may be penalized for failing to meet that outcome.[179] Ultimately, a properly designed "PBR framework rewards utilities for achieving well-defined outcomes (performance metrics) as opposed to simply incentivizing capital investment (inputs), which is the primary driver today of utility revenue and profits,"[180] ideally better "align[ing] the goals of customers, regulators, and utilities."[181] This can take numerous forms, many of which are controversial, and some of which could actually *exacerbate* the problems discussed in this article.[182] In Hawai'i, for example, a five-year multiyear rate plan "sets tight limits on the annual rate increases [Hawaiian Electric] will be allowed and largely divorces them from rate-

171. Order No. 679, *Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057 at P 270 (2006).

172. *Id.* at P 272.

173. *Id.*

174. *See Workshop to Discuss Certain Performance-based Ratemaking Approaches*, FERC (Sept. 10, 2021), https://ferc.gov/news-events/events/workshop-discuss-certain-performance-based-ratemaking-approaches-09102021.

175. Though incentive or performance-based ratemaking is relatively new to FERC, the concept dates back to the early 1900s. Branko Terzic, *The Incentive Theory*, FORTNIGHTLY, https://www.fortnightly.com/fortnightly/2015/12-0/incentive-theory.

176. *Policy Statement on Incentive Regulation*, 61 FERC ¶ 61,168, at p 61,588 (1992).

177. *Id.*

178. Benjamin Stafford & Liza Frantzis, *Performance-based Regulation: Aligning Utility Incentives with Policy Objectives and Customer Benefits,* UTILITYDIVE (Oct. 5, 2017), https://www.utilitydive.com/news/performance-based-regulation-aligning-utility-incentives-with-policy-objec/506498/.

179. In a particularly harsh variant, a utility may merely avoid a penalty by meeting the desired outcome. *See* Peter Navarro, *The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator*, 13 YALE J. ON REG. 105, 111 (1996).

180. Stafford & Frantzis, *supra* note 178.

181. Herman K. Trabish, *Can Performance-based Ratemaking Save Utilities?*, UTILITYDIVE (Apr. 17, 2014), https://www.utilitydive.com/news/can-performance-based-ratemaking-save-utilities/252683/.

182. For instance, absent a quality control mechanism, a performance-based rate could conceivably result in the utility "pursu[ing] cost savings at the expense of system reliability, safety, customer satisfaction, or other measures of quality." Navarro, *supra* note 179, at 105, 113.

of-return on capital investments."[183] The utility is thus incentivized to keep costs low in order to keep a greater proportion of its rates as profit. However, at the same time, separate incentives can reward utilities for excellent service and penalize them for underperformance, thus, mitigating the effects of the rate structure as a whole.[184]

It seems neither likely nor particularly desirable for FERC to entirely transition to performance-based ratemaking. However, it need not be an all-or-nothing proposition. Currently, some 19 states and the District of Columbia use PBR for individual performance issues—particularly issues that are segmented and easily quantifiable (for ease of verification).[185] The incentives (termed Performance Incentive Mechanisms or PIMs) adopted by the Hawai'i PUC are good examples. These include:

- Mechanisms to incentivize utilities to exceed Hawai'i's renewable portfolio standards. Utilities that fail to meet these standards will receive a $20 per megawatt-hour penalty; they will also receive an incentive of up to $20 per megawatt-hour for exceeding the standards (which will decrease over time).
- Mechanisms regarding customers' interconnection experience, meant to incentivize faster interconnection times for certain distributed energy resources (DERs).
- Mechanisms regarding low-to-moderate income energy efficiency, meant to promote customer engagement, equity, and affordability.
- Mechanisms regarding advanced metering infrastructure utilization, meant to accelerate the number of customers with advanced meters (thereby encouraging customer engagement and promoting DER effectiveness and grid efficiency).
- Mechanisms regarding grid services, also meant to promote DER effectiveness and grid efficiency.[186]

In Massachusetts, the Department of Public Utilities has "require[d] each distribution utility to submit a ten-year grid modernization plan that [would] reduce outages, optimize demand, integrate distributed resources, and improve workforce and asset management," as well as a "more specific, five-year, short-term investment plan that outlines the business case for the utility's capital investments in grid modernization."[187] Initially, performance metrics were mainly used to track

183. Jeff St. John, *Hawaii's Bold Step into Utility Performance-Based Ratemaking*, GREENTECH MEDIA (Feb. 10, 2021), https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/hawaiis-bold-step-into-utility-performance-based-ratemaking.

184. Whited et al., *supra* note 157, at 12-13; Trabish, *supra* note 181.

185. Chloe Holden, *Hawaii's More States Explore Performance-Based Ratemaking, But Few Incentives Are in Place*, GREENTECH MEDIA (June 13, 2019), https://www.greentechmedia.com/articles/read/more-states-explore-performance-based-ratemaking-but-few-incentives-in-plac.

186. Jeff St. John, *Hawaii's Bold Step into Utility Performance-Based Ratemaking*, GREENTECH MEDIA (Feb. 10, 2021), https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/hawaiis-bold-step-into-utility-performance-based-ratemaking.

187. William Boyd & Ann E. Carlson, *Accidents of Federalism: Ratemaking and Policy Innovation in Public Utility Law*, 63 UCLA L. REV. 810, 859 (2016).

utilities' progress; neither incentives nor penalties were used.[188] As of 2017, however, a rate case involving Massachusetts utility Eversource resulted in the creation of "a five-year [multiyear rate plan] with penalties of about '$50 million annually' for failing to meet existing safety and reliability standards."[189] The plan drew some criticism for failing to include new metrics or PIMs.[190]

Finally, in Illinois, PIMs are "layered on to existing [cost-of-service] rates"; they "impose[] penalty-only incentives for failing to improve reliability."[191] If utilities meet their performance metrics, they are allowed to "recover . . . actual costs plus a fixed return on equity;"[192] if they don't meet their performance metrics, they are penalized.[193] More recently, Illinois has also "added reward and penalty PIMs for energy efficiency programs."[194]

It may be equally appropriate for FERC to use similar performance metrics to supplement cost-of-service ratemaking, targeting areas where cost-of-service ratemaking fails to properly incentivize behavior. Utilities should not merely be rewarded for doing what they are supposed to do (provide safe and reliable service to customers), but a combination of incentives and penalties could balance the scales at reasonable costs to consumers. This would not be doable without some investment of time and resources by FERC. FERC could, for instance, track equipment failures—measuring things like the duration, frequency, and scale of the failures—and penalize utilities that experience more than a pre-determined number of failures per year. Likewise, FERC could penalize utilities for incidents where members of the public are injured or killed as a result of utility action or inaction. On the other hand, utilities could be rewarded for providing unusually reliable service (as measured by an unusually low number of equipment failures).

It is also important, though, to ensure utilities are doing what they need to do on a prospective basis so that maintenance backlogs do not build up to a point where catastrophic failures occur. FERC could, for instance, provide incentives to utilities who are replacing their transmission poles on a sustainable cycle. To promote public trust, the question of whether or not utilities have met their metrics could be evaluated by a neutral, independent third party that reports its findings directly to FERC.[195]

In certain cases, performance-based rates could be a powerful tool to ensure compliance. However, it is worth noting again the two major disadvantages that were mentioned above. First, they require a level of time and oversight that would probably require additional staffing and funding by FERC, or a (perhaps even

188. *Id.*

189. Trabish, *supra* note 181.

190. *Id.*

191. *Id.*; Whited et al., *supra* note 157, at 84.

192. Boyd & Carlson, *supra* note 187, at 810, 858.

193. Whited et al., *supra* note 157, at 84.

194. Trabish, *supra* note 181.

195. Whited et al., *supra* note 157, at 31 ("Where commissions have implemented performance tracking and reporting, commission staff frequently review and verify data, but independent third-party evaluators are also used, particularly when financial rewards or penalties are at stake. Greater use of third-party evaluators may help to prevent performance incentive gaming, such as that which occurred in California in the 1990s-2000s.").

more expensive) contract with an independent overseer. Second, if implemented poorly, they could even become a sinecure, rewarding utilities for conduct that it has always been their obligation to undertake in exchange for the opportunity to earn a reasonable return. (This is, of course, an oft-mentioned criticism of incentive rates). They may still be appropriate, particularly in cases where FERC needs to encourage very specific conduct.[196] But the tracker mechanisms we discuss next may, in many cases, achieve the same goals at reduced cost.

D. FERC Could Adopt Earmarked Funds for Particular Cost Items.

Tracker mechanisms—sometimes known simply as "cost trackers"—"allow utilities to use a formula or predefined rule to recover specific costs from customers outside of general rate cases" and are meant to "provide timely recovery of significant costs that are beyond utility control . . . reduc[ing] utilities' financial risk without compromising their performance and without, in the long run, increasing costs to customers."[197] Examples of tracker mechanisms include fuel adjustment and purchased gas adjustment clauses;[198] asset replacement riders; inflation riders; asset development riders; energy efficiency riders; renewable energy riders; environmental cost riders; weather normalization clauses; and revenue decoupling riders.[199] Tracker mechanisms and earmarked funds have been semi-regularly used by state commissions but have generally not been used widely at FERC.

Historically, FERC policy has generally "disfavor[ed] trackers for costs other than fuel."[200] In the pipeline context, that began to change in 2014, when FERC issued a "Proposed Policy Statement [that] would permit interstate natural gas pipelines to establish a tracker or surcharge mechanism to recover facility upgrade costs related to anticipated pipeline safety, reliability, and environmental regulations, if certain standards [were] met."[201] In 2015, FERC issued a second policy statement, which "closely tracked" the first statement—including the standards that must be met for a pipeline to recovers its modernization costs via a tracker

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196. Too often incentives are tied to the amount of utility investment alone, probably because that is a metric that may be easier to define and measure than outcomes or performance. And in many cases the level of investment may be a good proxy for performance, but that correlation need not hold and certainly not indefinitely.

197. Laurence D. Kirsch et al., ALTERNATIVE ELECTRICITY RATEMAKING MECHANISMS ADOPTED BY OTHER STATES, CHRISTIANSEN ASSOS. ENERGY CONSULTING LLC, at vii (2016), https://www.caenergy.com/wp-content/uploads/2016/02/Kirsch_Morey_Alternative_Ratemaking_Mechanisms.pdf.

198. Ken Costello, ALTERNATIVE RATE MECHANISMS AND THEIR COMPATIBILITY WITH STATE UTILITY COMMISSION OBJECTIVES, NAT'L REGIONAL RSCH INST., at vi (2014) ("[A] formula rate place could increase the chances of a utility passing through imprudent cost to customers.").

199. David E. Dismukes, Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms (Sept. 2010).

200. Emily Pitlick et al., *FERC Offers Analytical Framework for Pipeline Recovery of Costs Related to Safety, Reliability, and Environmental Compliance Costs and Requests Comments*, VAN NESS FELDMAN LLP (Nov. 21, 2014), https://www.vnf.com/339.

201. *Id.*

mechanism—and which went into effect in October 2015.[202] To date, however, FERC has yet to use these widely in the transmission context.

It is time to revisit that reluctance. Earmarked funds in particular could be a powerful tool to ensure that utilities—particularly utilities with a history of reliability problems—are actually spending the money necessary to maintain their system. Had the money PG&E requested for O&M each year in its rate cases gone into an earmarked fund instead of into the company's general funds, perhaps the maintenance backlog would not have persisted and the Camp Fire might never have occurred. That may (one hopes) be an extreme case. But FERC could create narrower funds as well—for instance, FERC could require earmarked funds for vegetation management or transmission line and pole replacement. Utilities that know they will only recover money for a specific purpose will be greatly incentivized to spend it for that purpose.

V. CONCLUSION

Our goal in this article is not to present a singular solution to the problematic incentive we have discussed, but rather to highlight the array of ratemaking tools FERC could use to address this problem if addressing it were viewed, fundamentally, as part of FERC's obligation to ensure just and reasonable rates. In fact, all of the tools we just discussed—ROE determinations, prudence reviews, performance-based ratemaking, and trackers or earmarked funds—can be powerful tools with which to counter the perverse incentives imbedded in traditional ratemaking tools and the resulting harms. In many cases, they might be most powerfully used in combination. For instance, many of the concerns that ratepayers and their advocates have with formula rates could be partially allayed by a robust culture of prudence challenges at FERC. Separately, earmarked funds for particular accounts will likely only come into play when potential wrongdoing by a utility has already been spotted; narrowly framed performance-based mechanisms, on the other hand, could work to head that wrongdoing off at the pass.

Critically, this versatile array of tools is already at FERC's disposal, as FERC's authority to use most—if not all—of these tools stems directly from the FPA. In other words, FERC does not need to wait for others, such as Congress, to act in order to be able to mount an effective response. Accordingly, what is needed is less a shift in law and more a shift in perspective— FERC should consider that its statutorily-mandated task is not only setting the rates at a theoretically appropriate numerical level. It is, as well, to use its broad jurisdiction to ensure that customers are also getting the safe and reliable service they pay for— i.e., it should consider price in relation to the service provided. As such, FERC should use the tools at its disposal more rigorously to ensure both that utilities are not unjustly and unreasonably securing higher profits for themselves by inappropriately reducing operating costs, and that authorized rates are used to maintain safe and reliable service, thereby protecting consumer interests and ensuring grid reliability.

202. David L. Wochner et al., *FERC Policy Statement Regarding Pipeline Recovery of System Modernization Costs,* K&L GATES LLP 1 (Apr. 29 2015), https://www.klgates.com/FERC-Policy-Statement-Regarding-Pipeline-Recovery-of-System-Modernization-Costs-04-29-2015.