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Alternative ratemaking in the US: A prerequisite for grid modernization or an unwarranted shift of risk to customers?

ABSTRACT

With increasing frequency, investor-owned electric utilities are requesting preferred cost recovery for "grid modernization" in multiple forms, from multi-year rate plans to riders. Utilities' claims that massive grid investment is necessary, and that exceptional investment requires exceptional cost recovery, are typically accepted by policymakers with little challenge. It is difficult for policymakers to resist the siren call of grid modernization's perceived outcomes, from improved reliability and resilience to reduced risks to safety and new customer technology adoption (electric vehicles, distributed energy resources, and more). This paper provides a contrarian viewpoint that is virtually absent as policymakers consider alternative ratemaking practices. It introduces the possibility that excess grid investment in the name of modernization is not only possible, and economically harmful, but has already occurred, encouraged by alternative ratemaking. It provides examples of common grid modernization expenditures the authors have identified as cost-ineffective in the course of their work. It also describes traditional grid planning practices with proven ability to address changing requirements over time, calling into question the need for exceptional grid modernization investment plans. Most important, the paper explains the moral hazard inherent in alternative ratemaking, and the fundamental shift in ratemaking risks and responsibilities from utilities to customers that results. The perspectives this paper presents are critical for policymakers to understand before adopting, extending, or expanding alternative ratemaking practices in their respective jurisdictions.

1. Introduction

It's hard to argue against having a "modern" grid. Legislators and regulators are agreeing with the hype and encouraging rate base growth. Multi-year rate plans (MYRP) are the latest alternative ratemaking trend.[4] Formerly restricted to California and Georgia, MYRP have expanded in recent years to New York, Maryland, Illinois, and Washington. "Modernization" riders have become increasingly popular too (Illinois, Indiana, Florida, Massachusetts, Minnesota, Missouri, Ohio, and several others). Policymakers hope these ratemaking alternatives will prompt utilities to make the massive grid investments perceived to be "required" for reliability, resilience, electric vehicles, distributed energy resources, or safety (wildfires).

Investor-owned utilities (IOUs) are only too happy to oblige, and need to grow rate bases to hit earnings targets promised to Wall Street. Investor presentations brim with claims of 7–8% compound annual rate base growth in coming years. Utility share prices and executive option payouts are climbing in anticipation of earnings growth. Yet utilities have been finding deregulation, integrated resource planning, and falling demand restrict the need for new generation. They are also discovering that long lead times make transmission a mid- to long-term growth prospect at best. For near-term earnings growth, distribution grids appear to have become the favorite destination of utility capital in recent years. A chorus of vested interests chime in, including utility suppliers and consultants; some environmental advocates; EV manufacturers; the ASCE and labor unions; and others who believe they will benefit from increasing grid investment.

But do customers and state economies benefit from alternative ratemaking and massive increases in grid investment? Is it possible that the benefits of exceptional grid investment have failed to compensate utility customers and society adequately for associated rate increases? Does the law of diminishing returns apply to grid investment? Are utilities proposing grid investments that are premature, or of the wrong type, or in the wrong places, or in the wrong capabilities? As experts to consumer, business, and environmental advocates on distribution business planning, investment, operations, and performance, we see evidence of all of these, as indicated in Fig. 1. Despite a 35% increases in gross distribution plant per customer among U.S. IOUs since 2013, service interruption frequency has deteriorated 3%, and service interruption duration has deteriorated 12%.

While everyone wants the distribution grid to be more reliable, the law of diminishing returns indicates that it is indeed possible to spend more to improve reliability than the improvements are worth to customers and state economies. A fundamental principle in economics first identified in the 1700 s,[5] Oxford defines the law of diminishing returns as "a principle stating that profits or benefits gained from something will

[4] National Conference of State Legislatures at https://www.ncsl.org/research/energy/modernizing-the-electric-grid-state-role-and-policy-options.aspx.

[5] Turgot. *Observations on a Paper by Saint-Peravy*. "Even if applied to the same [agricultural] field, it [the product] is not proportional [to advances to the factors], and it can never be assumed that double the advances will yield double the product." 1767.

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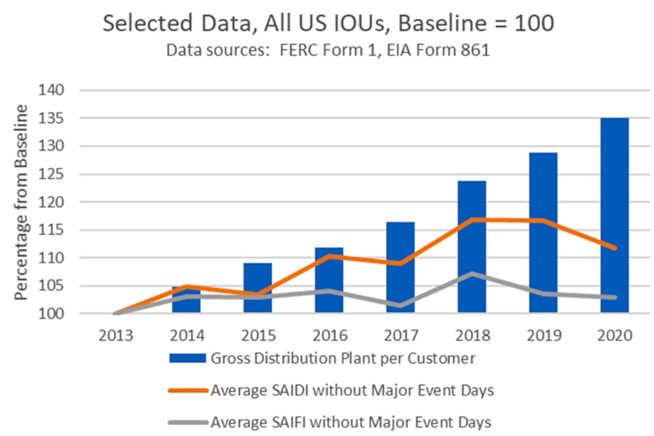

Fig. 1. Reliability Performance Relative to Distribution Plant per Customer, U. S. Investor-Owned Utilities, 2013–2020. (Higher system average interruption duration and frequency indices, SAIDI and SAIFI, indicate deteriorating reliability.).

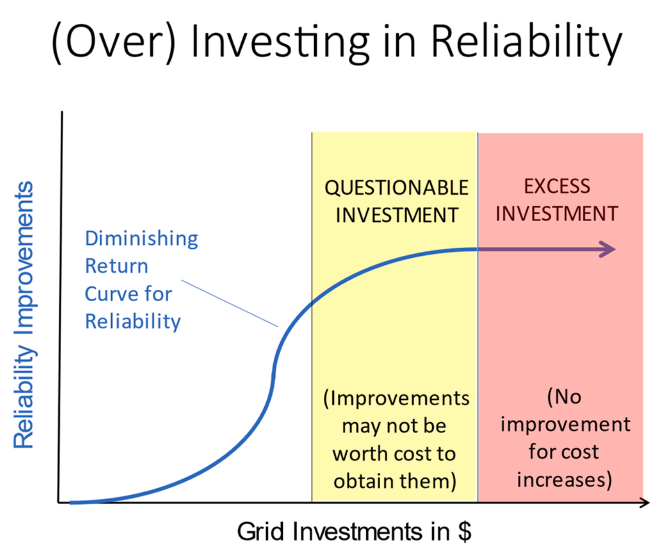

Fig. 2. The Law of Diminishing Returns Applied to Distribution Grid Reliability and Investment.

represent a proportionally smaller gain as more money or energy is invested in it." Fig. 2 applies the principle to reliability and grid investment. As discussed later in this paper, a utility under alternative ratemaking may have an incentive to over invest. One reason is moral hazard: a utility faces a return-risk calculus that is suboptimal, at least from the perspective of customers and state economies. Using grid modernization as a justification, a utility can significantly expand its rate base to increase its profits while passing through most if not all of the risks to customers.

Policymakers have generally bought utilities' pitch that as the generation, transmission, and distribution of electric energy changes, utility regulation must change with it. While this may or may not be true, controls against over-investment will continue to be a major responsibility of good regulation. While alternative ratemaking such as MYRP and riders may have some attractive qualities, moderating rate base growth is not one of them. Further, while DER and electric vehicle accommodation are important goals, reducing capital spending controls is not necessarily the best way to pursue them.

This paper argues that alternative ratemaking methods – the capital cost recovery of MYRP and modernization riders specifically – emasculate the existing controls by shifting risks and responsibilities from utilities to customers. It argues that cost disallowance risk essentially falls to zero under MYRP and "rider" ratemaking; that these constructs create a moral hazard; and that excess investment becomes inevitable. Our paper begins with examples of misplaced grid investments and planning processes that have resulted from alternative ratemaking to date.

2. The grid is not short of investment; it suffers from cost-ineffective investment

The American Society of Civil Engineers implies the U.S. energy grid has been neglected, giving it a "C-" rating in its most recent infrastructure report card.[6] Fig. 1 indicates that the U.S. electric distribution grid has seen massive investments in recent years, and that a lack of grid performance, not a lack of grid investment, is the issue. Most laypersons have trouble believing that increased grid investment fails to deliver improved grid performance, though independent research confirm this.[7] Based on the investments that typically pass for "modernization", the authors can explain the difference between the hype and the reality. Examples include smart meters, prospective equipment replacement, undergrounding of overhead lines, and advanced distribution management systems, to name just a few.

2.1. Smart meters

Exhibit number one in sub-optimized distribution investment is smart meters. Though some utility customers benefitted through reductions in manual meter reading costs, most utilities had already automated meter reading. This left just energy efficiency and demand response as the greatest potential benefits from smart meters at most utilities.[8]

Yet the throughput incentive (i.e., higher sales, higher short-term profits) makes the use of smart meters for energy efficiency, from conservation voltage reduction to improved consumer energy management tools, anathema to utilities. Demand response is antithetical to the capital bias that exists for investor-owned utilities. Why then should we be surprised that utilities are doing little to ensure the delivery of these potential benefits, as a well-known ACEEE report identifies?[9] Further, the authors observe utility claims that smart meters can markedly improve reliability are declining, as indicated by smart meter deployment proposals we have examined in the course of our work.

2.2. Prospective equipment replacement

Prospective equipment replacement is another investment that fails to deliver benefits in excess of costs, as some of the co-authors have already reported.[10] By some accounts, prospective equipment does not even constitute "modernization": it consists of replacing equipment of no or low book value (thus earning no or low profits for utilities) with new equipment of the same type. Most experts define grid 'modernization' to be the digitization of the grid through increased abilities to

[6] *America's Infrastructure Report Card (Energy)*. American Society of Civil Engineers. 2021.

[7] Larsen P, LaCommare K, Eto J, and Sweeney J. *Assessing Changes in the Reliability of the U.S. Electric Power System.* Lawrence Berkeley National Laboratory report 188741 prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. Pages 37–38. August, 2015.

[8] Alvarez, P. *Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment*. Second Edition. Table 18, page 159.

[9] Gold R, Waters C, and York, D. *Leveraging Advanced Metering Infrastructure To Save Energy*. American Council on an Energy Efficient Economy report U2001. January, 2020.

[10] Alvarez P, Ericson S, and Stephens D. *Asset Replacement Based on Risk Modeling: Emerging Best Practice?* Public Utilities Fortnightly. Part 1, August 2020 p.58; Part 2, September 2020, p. 72.

monitor grid conditions, analyze those conditions with software, and take appropriate action in near real-time. However some states have included prospective equipment replacement in the definition of "modernization", resulting in cost-ineffective investment.

Further, all utilities already employ objective procedures to identify assets in need of replacement before they fail in service, from substation equipment chemical and functional testing programs, to pole inspection and testing programs, to worst-performing circuit programs. Yet, because of MYRP and 'modernization' riders, prospective equipment replacement based on projections of failure due to age and subjective assessments of condition is becoming regrettably commonplace.

Given the objective testing programs all utilities have successfully employed to identify equipment in need of replacement, equipment failure "prediction" is both insufficiently accurate and unnecessary, offering extremely small reliability improvements relative to the extremely high cost of prospective equipment replacement. No research indicates that prospective equipment replacement delivers benefits relative to costs greater than those available from the practices listed above, which utilities have historically employed to identify equipment in need of replacement.

An analogy employing light bulbs can help the reader understand the failure in logic of prospective equipment replacement. Assume that the average lifespan of an incandescent light bulb is 4 years. Would the reader replace every light bulb in his or her home as it reaches 4 years of age simply because the average life was reached? Probably not.

Granted, the consequences of a failure in service of a critical piece of substation equipment are much greater than that of a light bulb. But all utilities maintain periodic testing programs that offers accurate, objective indications of failure for critical substations assets like power transformers, switches, circuit breakers, and relays. Such testing allows utilities to identify substation equipment in need of replacement in advance of a failure, thereby avoiding service outages affecting large numbers of customers. Should a utility replace a fully depreciated piece of substation equipment after it passes such tests? Probably not. Yet this is precisely how many utilities are replacing substation equipment prospectively, with little or no reliability benefit to show for it.

2.3. Undergrounding overhead distribution lines

Undergrounding overhead distribution lines is yet another extremely costly way to deliver reliability improvements. Though intuitively and aesthetically appealing, undergrounding's extreme cost – between $1 million (Florida) and $3 million (California) per mile – means it is simply not a cost-effective way to reduce reliability risk. Given that the average for-profit utility in the U.S. serves just 40 customers per distribution line mile, the reliability benefits simply cannot justify a cost of $25,000 to $75,000 per premise. Independent research confirms that even the most generous benefit definition, from a hurricane state (Texas), delivers just $0.30 in benefit for every $1 spent.[11]

Besides, undergrounding is no panacea. In the authors' experience, underground lines are more subject to outages from excavation and flooding than overhead lines. Faults in underground lines require additional time to locate and repair than faults in overhead lines. Finally, more aggressive tree-trimming and increases in right-of-way radii can deliver some of the same reliability benefits as undergrounding at a dramatically lower cost.

2.4. Advanced distribution management systems

An Advanced Distribution Management System (ADMS) is another typical component of grid modernization plans. However the authors note that it is the individual software components of ADMS, not an ADMS itself, that delivers benefits. Fault location, isolation and service restoration (FLISR); DER management systems (DERMS); grid power flow modeling; outage management systems (OMS); integrated volt-VAR control (IVVC, used to implement conservation voltage reduction); demand response management systems (DRMS); and other components are the sources of value. These are available for deployment individually; in the authors' experience, ADMS simply combines these together into a single platform. Given that needs vary greatly by utility and over time, ADMS can represent a financial boondoggle relative to the deployment of individual capabilities on an as needed basis.

Further, utilities' stated expectations that ADMS will usher in a wave of operations automation and grid optimization are unrealistic and potentially infeasible. For ADMS to operate in this manner assumes a degree of accuracy between the physical world (equipment types, locations, phases, settings, capabilities, capacities, etc.) and the virtual world (data in utilities' geographic information systems, or "GIS") that simply does not exist at any utility. In the authors' experience, herculean field organization efforts are required not just to secure such accuracy, but also to maintain it over time. As a result, "advanced" ADMS capabilities simply will not work as advertised,[12] and thus will be ignored by grid operators. ADMS investments driven by a desire to grow rate base, rather than as solutions to needs identified by grid operators and traditional grid planning practices, will be premature.

These are just a few examples. Certainly, grid planning practices can and should prepare the grid for the future, as the next section of this paper will discuss. But the track record of alternative ratemaking, and the associated increases in grid investment it encourages, is not good. Fig. 3, which shows a performance review from a few states that have had MYRP and grid modernization riders in place for several years, attests to this.[13] The states with the longest-running MYRP ratemaking, California and New York, have seen no reduction in service interruptions in recent years despite massive grid investments. The states with the longest-running grid modernization riders, including Illinois, Indiana, and Ohio, have seen marginal if any reduction in service interruptions, despite billions in grid modernization investments per state.

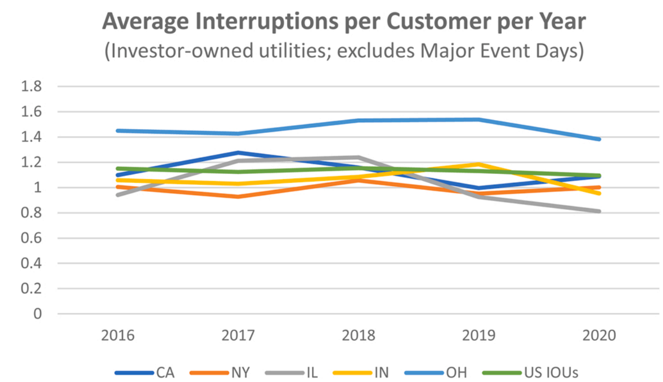

Fig. 3. Average Interruptions per Customer per Year without Major Event Days, 2016–2020, Customer of Investor-Owned Utilities in CA, NY, IL, IN, and OH compared to the average for U.S. investor-owned utilities.

[11] Larsen P. *A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines*. Lawrence Berkeley National Laboratory report 1006394. Section 4.3, page 35. October, 2016.

[12] *Voices of Experience: Insights into Advanced Distribution Management Systems*. Office of Electric Delivering and Energy Reliability, U.S. Department of Energy. February, 2015.

[13] U.S. Energy Information Administration. System Average Interruption Frequency Index by State without Major Event Days as reported by U.S. Investor-Owned Utilities, including such utilities serving customers in CA, NY, IL, IN, and OH on Form 861, 2016–2020.

3. Traditional grid planning, indistinct from modernization plans, will deliver the grid we will need

To guard against cost-ineffective grid modernization spending, most alternative ratemaking designs require advance spending plans from utilities. This has typically involved distinct plans and planning processes dedicated to "modernization" investments. But the authors caution that a separate modernization planning process abandons the traditional grid planning practices utilities have employed successfully in the past. These traditional grid practices have historically accommodated both new customer technologies and new utility technologies as they have become available over time. Yet in recent years such practices have been typically criticized as inadequate by both utilities and some stakeholders, including environmental stakeholders concerned that the grid will not be ready for electrification or DER.

3.1. Capital bias as a serious concern

In examining the utility position, we know that capital bias drives an interest in accelerating rate base growth. A distinct grid modernization planning process both 1) satisfies regulators' advance planning requirements; and 2) is likely to justify (accurately or not) greater investment than traditional grid planning practices would. Utilities thus have shown little interest in describing how traditional planning practices would ensure grid "readiness", and readily agree to a separate planning process for modernization. Regarding environmental advocates with grid readiness and planning concerns, the authors know of no such advocates with direct experience creating grid investment plans using traditional planning practices.

The authors, with extensive grid planning, investment, operations, and performance experience, including experience in geographies with relatively high customer adoption of electric vehicles and DER, present a different perspective. While some modern grid management software does make sense to deploy in advance, the traditional approach to grid planning has evolved to accomplish exactly the same goals as "modernization". That is, that the right capabilities (none extraneous) are in the right places (to no greater extent than necessary) at the right times (in advance, but no earlier than necessary). No separate planning process for modernization is needed or advisable.

3.2. No need to replace traditional planning

Traditional grid planning consists of a periodic, methodical approach to identifying and satisfying grid needs in advance through a circuit-by-circuit, substation-by-substation review. The review compares load and DER forecasts to existing capacities and capabilities, and also considers grid performance goals. This traditional grid planning process was recently documented by a joint NARUC-NASEO task force on comprehensive electricity planning in its "Jade Cohort Roadmap".[14] (The Roadmap recognized that a distinct planning process for "modernization" is an option, but does not offer an opinion on this, and the authors were not consulted.).

In the authors' experience, there is no requirement or advantage in separate planning for grid modernization. Indeed, a separate grid modernization planning process can be associated with disadvantages, such as premature or unnecessary investment. To summarize, separate grid modernization planning is an artifact of grid modernization riders, not a benefit of such riders. There is nothing unique about modern customer or utility technologies that traditional grid planning practices cannot manage in the absence of a separate grid modernization planning process.

Let's consider a few examples, starting with transportation electrification. Whether personal, or fleet, or public, electric vehicle charging overwhelmingly takes place at night, when both transportation needs and grid loads are the lowest. Time-of-use rates enabled by smart meters further encourage this beneficial charging behavior.[15] This means that capacity increases required to accommodate transportation electrification are still pretty far off. In 2021, over 96% of passenger cars sold in the U.S. were still powered solely by internal combustion engines.[16] Those vehicles are going to remain in service for the next 20–25 years; no overnight transformation is imminent.

Many observers also tout electrification of the built environment as a need for grid modernization. The authors note that billions of dollars of unpaid natural gas distribution investment exists in almost every state. In many states, this number grows by the day as safety programs dictate pipeline replacements. We note that these investments are matched by untold billions in related customer investments (natural gas furnaces, water heaters, stoves, etc.). It will take decades and decades to wean the public off this grid, even if a concerted, neighborhood-by-neighborhood planning effort were to begin in every state tomorrow. There is plenty of time for the grid to evolve to meet electrification needs.

Regarding distributed energy resource (DER) accommodation, we find policymaker and environmentalist fears that the grid will not be ready to be similarly exaggerated. The most common form of DER, photovoltaic (PV) solar panels mounted on residential and commercial building rooftops, are not a threat to grid reliability. DER located near customer loads, and in particular inverter-connected loads like PV Solar and batteries, are unlikely to cause grid issues until very high adoption levels are reached. Hawaii's experience and independent research confirms this.[17]

A circuit-by-circuit review of DER growth forecasts, incorporated into traditional grid planning practices, will be sufficient to identify and construct any associated grid accommodations that may be required in advance of need. In the authors' experience, large utility-scale DER is the type most likely to require large grid investments to accommodate; but predicting locations for such installations in advance is difficult, and preparing an entire grid for all such possible locations in advance is cost-prohibitive.

To summarize, rate base growth and resulting rate increases are being incurred for no documented benefits to date – a situation that is no doubt detrimental to both utility customers and state economies. While utilities tout the jobs created by their investments, empirical evidence shows that higher utility rates reduce overall employment.[18] But near-term economic risks from excess grid investment are not the only ones suffered by customers and state economies.

Grid investment too far in advance can be placed in the wrong locations, and are at risk for technological obsolescence. In some cases, the authors expect grid investments to become obsolete, or to be fully depreciated, before the need to employ associated capabilities actually arises. In the past, cost disallowance risk discouraged for-profit utilities

[14] NARUC-NASEO Comprehensive Electricity Planning Task Force. Blueprint for State Action, Jade Cohort Roadmap. Page 5, Jade Cohort (distribution grid) Flowchart of Idealized Comprehensive Electricity Planning Process. February, 2021.

[15] Smart J and Salisbury S. *Plugged In: How Americans Charge Their Vehicles*. Idaho National Laboratory. July 1, 2015, Figure 10, page 17. (In San Diego, where electric rates are lowest from midnight to 5 am, EV charging during this time exceeded charging relative to other times of day at an approximate ratio of 6:1.)

[16] Clifford, C. *"Electric vehicles dominated Super Bowl ads, but are still only 9% of (global) passenger car sales."* CNBC Blog Post February 14, 2022. Available via internet at https://www.cnbc.com/2022/02/14/evs-dominated-super-bowl-ads-but-only-9%-of-passenger-car-sales.html

[17] Hoke, A et al. *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*. National Renewable Energy Laboratory preprint JA-5500–55094. July, 2012.

[18] Garen J, Jepsen C, and Saunoris J. *The Relationship between Electricity Prices and Electricity Demand, Economic Growth, and Employment.* University of Kentucky Center for Business and Economic Research Report. October 19, 2011.

from taking such risks. But with alternative ratemaking, cost disallowance essentially falls to zero, creating moral hazard, encouraging premature and unnecessary investment, and shifting investment risks and ratemaking responsibilities from utilities to customers. We now turn to a detailed explanation of why alternative ratemaking has effectuated these negative outcomes, doing harm to electricity customers and state economies in the process.

4. Alternative ratemaking creates moral hazard, shifting risks and responsibilities from utilities to customers

If alternative ratemaking such as MYRP and riders have led to misplaced grid investment and planning practices, the reader may ask why alternative ratemaking is so popular among legislators, regulators and utilities. The reader may also ask if such popularity comes at a cost to customers and state economies. The answer can be found by examining two cost controls that are the foundation of the balance of power between customers and shareholders: regulatory lag and cost disallowance risk.

4.1. Regulatory lag as a benefit

Alternative ratemaking proponents generally tout the reduction or elimination of regulatory lag on capital as a benefit of MYRPs and riders. Regulatory lag – or the timing difference between a utility's cost increases and associated rate increases – is perceived by many as discouraging utility investment at a time when grid investment needs are perceived as high. No regulator wants to author orders which could be perceived as anti-investment, anti-reliability, anti-environment, or anti-safety.

But while regulators are routinely reminded by utilities that regulatory lag discourages investment, and is therefore a bad thing, regulators must also consider the benefit of regulatory lag: that it acts as a control against premature or unnecessary investment, thereby helping to balance shareholder and customer interests. The notion that regulatory lag can be a good thing merits additional discussion.

Historically, regulators have favored, not discouraged, regulatory lag specifically because it acts as a built-in cost control. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs.[19] The reason is that when a utility experiences higher costs, the longer it has to wait to recover those costs, thus lowering its earnings. Consequently, the utility would have an incentive to minimize its costs.

Regulators have thus historically relied on regulatory lag as a critical element in motivating utilities to act efficiently. One reason for this is that regulators recognize the difficulty of determining the prudence of investments, which requires highly technical resources whose costs are beyond the reach of most regulators. Instead, regulators came to rely heavily on regulatory lag as a mechanism to control a utility's costs. Ironically, one can therefore oppose alternative ratemaking precisely because it reduces regulatory lag, when lately the major argument in favor of alternative ratemaking is reduced regulatory lag.

4.2. Importance of balancing interests

Regulators' foci appear to have shifted from the value of regulatory lag as a legitimate and effective cost control designed to balance customer interests against shareholder interests, to encouraging grid investment. The problem is that regulators' duties should lie with balancing interests rather than encouraging investments per se. The notion that grid investment should be ever-increasing rests on a series of unreliable assumptions, including 1) that if an increase in grid investment is good (unproven), then 2) ever-increasing grid investment must be better (contradicting the law of diminishing returns), and thus 3) regulatory lag is something to avoid (an errant conclusion).

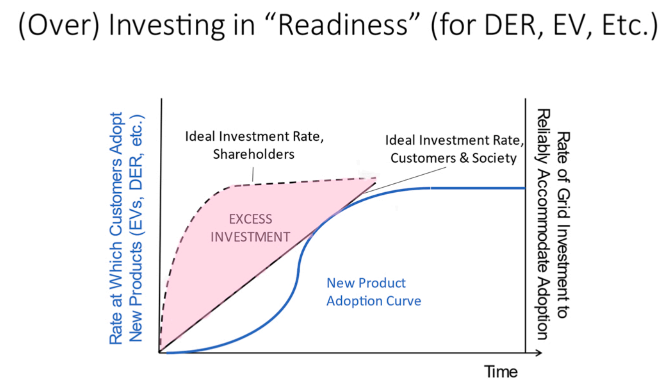

Fig. 4. Illustration of the difference between a grid investment level required to be "Ready" for customer technology adoption vs. the level of investment that for-profit utilities prefer as a regulated profit growth strategy.

Utilities are not the only parties in favor of alternative ratemaking and increasing investment. Ever-increasing grid investment is supported by an "Iron Triangle" – including not just for-profit utilities, but Wall Street and some "agenda" advocates[20] – with utility customers on the other side as skeptics. These vested interests are not concerned about the regulatory implications of alternative ratemaking (the shift in risk from shareholders to customers), nor do they have experience in grid planning or operations. Both claims these vested interests make – that massive grid investment is needed now for "readiness", and that alternative ratemaking is a prerequisite for such investment – must be rigorously challenged by regulators and legislators, who are advised to consider the motivations and qualifications of those making these claims.

The authors, who count several environmental advocates as clients, sympathize with those who want the grid to be "ready" for DER, or for electrification, and other priorities driven by climate change. The authors want the grid to be "ready" too. But we do not subscribe to the theory that controls on capital investment should be abandoned in pursuit of grid readiness. Consider Fig. 4. While acknowledging that advance investment is indeed required to prepare the grid for anticipated technology adoption, Fig. 4 also documents that for-profit utilities have an economic incentive to over-prepare. As discussed earlier, over-preparation carries the risks of premature investment and technological obsolescence – risks that are passed on to customers under alternative ratemaking practices in the form of unnecessary rate increases.

The adoption curve in Fig. 4 is a representation of a phenomenon observed for all new technologies across industries and products, from color televisions in the 1970′s to mobile phones in the 1990′s. Experience has shown that the diffusion of new technologies is a gradual process. The fraction of potential users that invests in a new technology typically follows an S-shaped path over time, rising only slowly at first, then experiencing rapid growth, followed by a slowdown in growth as the technology reaches maturity and most potential adopters have switched.[21]

[19] Kahn, A. *Economics of Regulation*, Vol. 2 (New York: John Wiley & Sons, 1971).

[20] For example, RMI (formerly the Rocky Mountain Institute), a prominent clean-energy advocate, has remarked that: "To support a clean yet reliable, flexible, and safe power system, utilities need to invest in new resources and technologies. PBR mechanisms, such as multi-year rate plans or other regulatory tools like cost trackers, can provide utilities with longer-term revenue certainty and more immediate cost recovery to support these more nontraditional investments." [https://rmi.org/five-lessons-from-hawaiis-groundbreaking-pbr-framework/].

[21] Jaffe A. et al., Technological Change and the Environment, RPP-2001–13 (Cambridge, MA: John F. Kennedy School of Government, October 2001), 41.

Fig. 4 also indicates that some amount of advance investment in the grid is advisable, as it may not be possible to ramp up grid investment as rapidly as required at some points of the adoption curve. The appropriate amount of advance investment is an open question, but could be guided by the concept of *real options*. Real options theory says that when the future is uncertain, it pays to have a broad range of options available, and to maintain the flexibility to exercise those options.[22] To those who claim massive investment is required now, investment at the level suggested by real options theory may represent a reasonable, and more cost-effective, alternative to massive investment as encouraged by alternative ratemaking.

Finally, Fig. 4 documents the results of utility capital bias combined with a relaxation of capital cost controls. For-profit utility investment levels result from a risk vs. reward calculus. Utility managers weigh the rewards of capital investment (earnings growth) against its risks (cost disallowances by regulators). The lower the cost disallowance risk, the lower the likelihood that a for-profit utility will incur a cost for premature, or unnecessary, or incorrect investment decisions. For-profit utilities protected from such consequences are more likely to invest prematurely, or unnecessarily, or incorrectly when the consequences of such decisions are shifted to consumers (see next).

4.3. Cost disallowance risk as a control on capital investment

Finally, while utilities obviously want to reduce or eliminate regulatory lag, another big payoff is in reducing, if not effectively eliminating, cost recovery risk. For both MYRP and modernization riders, utilities are required to present investment plans in advance. A few states, including Massachusetts and Minnesota, go so far as to "pre-authorize" or "pre-certify" grid modernization investments presented and reviewed in advance.[23] In instances when utilities present grid investment plans in advance (MYRPs and modernization riders), cost disallowance is practically impossible, for two reasons. These reasons persist despite specific legislation or regulation which preserves regulators' right to disallow costs for recovery from customers.

First, any stakeholder electing to challenge an investment after a utility has spent capital is likely to face a credible and logical utility argument. That argument is, "Ms. Stakeholder, if you had a problem with our grid investment plan, why didn't you challenge it when we provided our plan for review, before we spent capital?" Regulators will have difficulty dismissing such arguments. Second, utility grid investment plans, including modernization plans, are typically denominated in hundreds of millions if not billions of dollars. Disallowances of even small proportions of such massive investments have big impacts on utility cost of capital, and thus customer rates.

In a sense, MYRPs and riders put regulators in a Catch-22. At the end of an MYRP period, or in a rate case, utilities ask to add previously presented and reviewed investments to rate base. When presented with a grid investment that failed to deliver benefits in excess of costs, a regulator can 1) allow the investment into rate base, which harms consumers and state economies; or 2) disallow cost recovery on the investment, which increases a utility's cost of capital, thus harming consumers and state economies.

4.4. Shifting risk to customers upsets the balancing act

As a result, alternative ratemaking shifts risk to customers, jeopardizing both economic efficiency and "fairness." In their duties, regulators must acknowledge the interests of individual groups by avoiding actions that would have a devastating effect on any one group. Since regulators implicitly or explicitly assign objectives to ratemaking, logically they should evaluate mechanisms on how they advance certain objectives while not seriously impeding others that are integral to good ratemaking. For alternative ratemaking, this means that regulators should look at the incentive and equity implications as well as the financial effects on the utility.

There is also the important question of who can better absorb risk: the utility or its customers? Optimal risk sharing depends on: (1) who has control over risk? (2) who can better shoulder risk and is less risk averse? and (3) who can bear risk more cheaply? On the first point, utilities obviously have the ability to manage their costs. Utility investors would seem to be better able to shift their financial portfolio under adverse utility-financial conditions than for utility customers to switch providers when, say, utility rates rise unexpectedly high. This infers that more risk should fall on utility investors rather than utility customers.

A difficult but critical task for regulators is to translate stakeholders' interests into the public interest. This is an essential feature of the "balancing act" of regulation in which regulators try to avoid certain outcomes, notably excessive rates and suppression of utility investors.[24] Given the reductions in regulatory lag and cost disallowance risk, few people doubt that alternative ratemaking is beneficial to utilities and their investors. The tough question for regulators is how alternative ratemaking promotes the interest of utility customers. The answer is unclear.

The regulatory "balancing act" often uncovers the extreme positions of parties, whether they are utilities or intervenors. It requires regulators to tradeoff the various ratemaking objectives in deciding what best serves the public interest. For example, although alternative ratemaking tends to help the utility financially, it may expose customers to excessive risks and other costs (e.g., moral hazard) that make riders contrary to the public interest. It is somewhat puzzling then why regulators are so keen on a ratemaking mechanism that is so imbalanced in favor of utility shareholders at the expense of customers and state economies.

4.5. MYRPs and riders create moral hazard

In response to these concerns, utilities claim that regulators always maintain cost disallowance authority, and that stakeholders now have two opportunities to challenge utility investments. But do they? Stakeholders have never had access to the kinds of technical expertise required to challenge complex electrical engineering justifications for investments. Further, the limited discovery periods associated with MYRP, or rate cases, or grid modernization plan review, do not permit stakeholders to secure, let alone understand, the voluminous and complex technical information required to evaluate utility grid investment proposals. These obstacles, known commonly as information asymmetry, have always proved difficult to surmount. Instead, stakeholders have always counted on regulatory lag and cost disallowance risk to control utility capital spending. Under alternative ratemaking, these controls over utility investment are now effectively missing.

Prudence reviews try to dissuade a utility from poor decisions with the threat of financial harm to encourage more discipline in investment plan development and execution. Given asymmetric information, where a utility knows more about its operations than the regulator or stakeholders, some analysts characterize prudence reviews as a second-best mechanism to market-like incentives to reduce costs. Throughout the history of public utility regulation, regulatory lag and prudence reviews have been the most prominent instruments used by regulators to assure that rates are just and reasonable. If they go missing or are seriously weakened, as with alternative ratemaking, a course correction becomes necessary.

[22] Avinash D and Pindyck R. Investment Under Uncertainty (Princeton, NJ: Princeton University Press, 1994). Also Pindyck R, "Irreversible Investment, Capacity Choice, and the Value of the Firm," The American Economic Review, vol. 78 (December 1988): 969–985.

[23] Massachusetts "pre-authorization" described at https://www.mass.gov/info-details/grid-modernization; Minnesota "pre-certification" example available in PUC Docket No. E002/M-20–680, Order dated July 23, 2020.

[24] Costello K. "*Let's Not Forget Balancing Act of Regulation.*" Public Utilities Fortnightly, October 2019: 46–9.

Others will argue "So, what has changed? Stakeholders have always had difficulty securing cost disallowances." What has changed is utilities' perception of cost-disallowance risk. While always considered by utilities as a low risk, cost disallowance risk is at its lowest point ever with MYRP and modernization riders, creating a moral-hazard situation. Moral hazard is a term economists use to describe a situation in which a market actor (in this instance a regulated utility) has no incentive to avoid risk (in this instance cost disallowance risk) because the actor is protected from its consequences (in this instance through preview of MYRP and modernization rider investment plans).

Moral hazard from MYRP and modernization riders is no different than that of the Great Recession of 2008, which was prompted in large part by mortgage makers who sold those mortgages to others, thus abdicating any accountability for making loans to people who were clearly not qualified to pay the loans back. Nor is the moral hazard created by MYRP and modernization riders any different from that created by government-paid flood insurance, which encourages people to rebuild homes destroyed by floods in flood plains. Protection from the consequences of a risk encourages greater risk taking, and utility investment is no different.

Historically, stakeholders could count on utility fear of cost disallowance risk (and to a lesser extent, regulatory lag) to help moderate utility investment levels. Utilities spent the capital required to distribute electricity safely and reliably, and bore the burden to prove prudence. Once grid investment plans are presented for review, given virtually zero cost disallowance risk, the burden shifts to stakeholders, who must identify questionable spending in advance. This would be fine if stakeholders had the information and expertise to recognize and challenge investments of questionable value or timing, from prospective equipment replacement to undergrounding, but they do not. There can be no denying that alternative ratemaking shifts risk from shareholders to customers, or that utilities are likely to take advantage of the moral hazard thus created.

4.6. Need for customer protections and performance monitoring

If the new approaches to ratemaking are to continue, regulators should require new provisions for customer protection. Ideas include (1) duration limits (for example, sunset provisions); (2) annual rate increase or investment caps; (3) deferrals/carrying charge limitations (for investments in excess of rate increase or investment caps); (4) O&M offsets or productivity offsets or specific cost savings associated with such capital spending, and any other charges in utility revenue requirements; (5) reduced rates of return (a result of lower utility financial risk); (6) excess earnings tests and customer sharing; (7) greater stakeholder participation in grid planning processes and development; (8) performance targets and benchmarks; and (9) penalties and incentives based on targets and benchmarks.

In advancing the public interest, regulation's central task is to induce high-quality performance from utilities. Achieving this requires regulators to measure a utility's performance along with reviewing utility decisions and other actions.[25] Since grid modernization programs are extremely expensive, regulators should demand that utilities demonstrate the benefits to customers from improved performance attributable to the capital expenditures recovered through alternative ratemaking.

5. Parting thoughts

We bring these perspectives to policymaker attention to encourage a re-evaluation of commonly-held beliefs that may be incorrect, including 1) massive grid investment is needed; 2) massive investment delivers reliability improvements and other benefits that justify the associated rate increases; and 3) without alternative ratemaking, utilities will not make grid investments at the required level. The reality is that no one is dictating what investments a utility should or should not make to provide safe and reliable service. Parties with vested interests are encouraging these beliefs, and policymakers are encouraged to consider them with a healthy dose of skepticism.

It is worthwhile to remember that for-profit enterprises operate as monopolies under state authority through a regulatory compact. Through the compact, legislators and regulators expect that such enterprises will make the investments required to deliver safe and reliable services, and they authorize rates of return on capital to compensate for investment risk. The prospects of load growth through electrification, or of self-service technologies such as PV solar, do not change the compact, nor this reasonable expectation. The regulatory compact has served our nation well in the past, through massive customer technology adoption (such as air-conditioning) and new utility technologies (from SCADA to solid-state circuit breakers). There is no reason to believe that it cannot continue to work well in the future.

Innovative technologies adopted by customers and utilities are not new. Indeed, it has been the status quo for the electric utility industry since the dawn of the 20th century. It is time to stop bribing distribution utilities for fulfilling basic expectations and accepting investment risks for which they are already well-compensated. Even in cases of legislated ratemaking reforms, interest in grid modernization does not relieve regulators of their responsibility to balance shareholder interests against customer interests.

It is time to question the appropriateness of increasing utility rewards, in the form of reduced regulatory lag, given increasing customer risk, in the form of reduced (if not eliminated) cost-disallowance likelihood. As in the past, regulators should expect that utilities will make the investments required to deliver safe and reliable service, in return for fair compensation opportunities through rates charged to customers. In this manner, the historical balance between shareholder interests and customer (and state) interests can be equitably maintained while the need for grid investment is appropriately pursued.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

Data will be made available on request.

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[25] Costello K. *"Performance Review of Utilities: Important but Proceed Cautiously."* Climate and Energy, April 2022: 13–8.

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