Multiyear Rate Plans and the Public Interest

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Executive Summary

Regulatory experts generally agree that ratemaking should strive to achieve high economic efficiency by utilities, fairness, and reasonable regulatory costs. These three outcomes have characterized good ratemaking going back to the beginning of public utility regulation. Economic efficiency requires utilities to create or adopt new technologies, achieve excellent operating performance, and set rates that correspond to marginal cost. All of these outcomes benefit the long-term economic well-being of utility customers in addition to advancing the public interest. Fairness means that neither customers nor utility shareholders unduly shoulder risks or retain the benefits of utility activities. Fairness is essential for the public credibility of the regulatory process and regulation itself. A large part of regulatory costs are the expenses incurred by utilities and other stakeholders during the course of general rate cases.

Traditional rate-of-return ratemaking has undergone critical review at least since the early 1960s. Various stakeholders and academic economists have offered proposals to improve, replace, or supplement it with mechanisms that attempt to redress the supposed deficiencies underlying traditional ratemaking. The primary question for utility regulators is whether these mechanisms are compatible with the objective of setting just and reasonable rates.

One such mechanism is multiyear rate plans (MRPs). MRPs are a price mechanism that sets a utility's base rates and revenue requirements for longer than a single 12-month period. MRPs specify rates beyond the rate effective year of a rate case by applying a formula or index, or detailed forecasts for allowable rate changes over the duration of the plan. For example, instead of a utility filing a new general rate case when conditions change, an MRP may forecast what these conditions are and adjust rates within a single rate case.

More state utility regulators, for example Georgia, Minnesota and Washington, in recent years have either approved MRPs or have expressed interest in them. The issues surrounding MRPs are more complex than what first meets the eye. Whether MRPs are in the public interest is the ultimate question for regulators to answer, but one that has no clear answer. Since MRPs involve so many facets of regulation, their merits come down to the features of a specific plan. Other countries, for example Australia, Canada and Great Britain, have relied on MRPs more than the U.S., often citing the deficiencies of traditional rate-of-return ratemaking.

The major supporter of MRPs in the U.S., electric utilities, have advanced different arguments. Their main one is that MRPs would improve the regulatory process and their financial condition (e.g., from less regulatory lag). From a regulatory perspective, their arguments seem to fall short of making a compelling case for how their customers would benefit. For example, utilities have emphasized the need for MRPs to facilitate recovery of capital costs between general rate cases. While this may benefit customers, MRPs have other effects on utility customers, either positive or negative. The mixed results from MRPs preclude a *prima facie* case for their approval by regulators.

This paper lays out a general approach for regulators in evaluating MRPs as a ratemaking mechanism with the potential to advance the public interest. It first discusses the expected benefits and outcomes of MRPs over traditional ratemaking practices. The paper then takes a more critical approach by accounting for the downsides of MRPs. The fact that relatively few utilities are currently operating under an MRP suggests that like most other mechanisms it has its costs as well as benefits. An overall evaluation therefore requires a cost-benefit review, which is not part of this research paper.

Utility customers can potentially benefit from MRPs in four major ways:

1. Lower prices;
2. More moderate price changes over time;
3. Utility supply of more services;
4. Higher reliability and improved customer service; and,
5. More immediate price benefits from improved utility performance.

For regulators, the question is: What would it take to produce these benefits? This paper attempts to answer this question, although some issues are beyond the scope of this paper.

This paper suggests that conceptually MRPs have attractive features that warrant serious attention by regulators. They represent a potentially sound approach to ratemaking that can improve the regulatory process and benefit utility customers. Having said that, a caveat is that the benefits to utility customers come down to on how MRPs are structured and executed. Certain features should be in place, for example to protect customers from excessive rates, to give utilities incentives for cost-efficiency, and to ensure customers that utilities are performing satisfactorily in vital areas such as service quality. When badly structured or implemented, MRPs can wipe out the benefits that potentially would flow to customers. As a crucial factor, when regulators are unable to determine whether a utility's revenue requirement forecasts reflect prudent management and are unbiased, they should discount the capability of MRPs to benefit customers. A positive public-interest outcome, in the end, turns to the details, which this paper identifies. A number of things can go wrong that would jeopardize the efficacy of MRPs to promote the public interest. That might, at least partly, explain why MRPs are relatively uncommon in the U.S.

Finally, although this paper does not definitely answer the ultimate question of whether MRPs are in the public interest, it aims to move ahead the dialogue on a ratemaking mechanism that represents a major if not radical departure from traditional ratemaking. More than anything, this paper attempts to educate state utility commissions on MRPs. It hopes to guide them by identifying those key elements of MRPs that are most crucial in affecting the long-run well-being of utility customers. Appendix A contains a list of generic questions about MRPs, some of which this paper tries to answer. Appendix B lists specific questions that regulators can ask about MRPs when initiated by them or proposed by stakeholders.

Table of Contents

I. Introduction 1

II. Features of Traditional Ratemaking 4

III. Objectives of MRPs 16

IV. Core and Add-On Features of MRPs 20

V. Specific Issues for Regulators 25

VI. Major Concerns with MRPs 35

VII. When Can MRPs Be in the Public Interest? 40

VIII. Summary and Final Thoughts 45

Appendix A: General Questions on MRPs 48

Appendix B: Questions for Regulators to Ask about MRPs 49

Multiyear Rate Plans and the Public Interest

I. Introduction

The main objective of this paper is to educate state utility commissions on multiyear rate plans (MRPs). An MRP is a price mechanism that sets a utility's rates or revenue requirements for longer than a single 12-month period. It specifies rates[1] beyond the rate effective year of a rate case[2] by applying a formula or index, or detailed forecasts for allowable rate changes over the duration of the plan. Instead of a utility filing a new general rate case[3] when conditions change, for example, an MRP may forecast what these conditions are and adjust rates within a single rate case. One common practice is to allow rates to automatically change for a specified post-test year period.[4]

MRPs differ from traditional rate-of-return (ROR) ratemaking (hereafter called "traditional ratemaking") in that they specify rates or revenues for future years applying data and other information beyond the rate effective year following a rate case. For example, if a rate case sets rates for 2017, a three-year MRP may specify that rates can further increase 3 percent in 2018 and 1 percent in 2019. Traditional ratemaking would determine, a rate increase of, say, 5 percent starting in 2017. Unless the utility files another general rate case, the new rate stays fixed. One perception of MRPs is that they are more of an adaptation to traditional rate-of-return ratemaking, rather than as a radically different ratemaking paradigm. For example, by forecasting revenue requirements out to 3 years, an MRP is just an extension of setting rates based on a future test year.

Many analysts view MRPs as superior to traditional ratemaking in advancing economic efficiency and other areas of utility performance. As discussed later, this outcome depends on how rates are set in the "out years".

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1 Rates in this context refer to base rates. Some MRPs specify allowable revenue changes, which has a different effect on utility behavior than specifying allowable rate changes. The former specification,

2 A rate effective year is the first year that new rates go into effect, which could coincide with a future test year.

3 A general rate case also typically covers a multimonth review period over which several parties participate. It is usually initiated at the utility's request, involves large sums of dollars, encompasses all rates, and includes a scrutiny of a utility's costs and revenues by different parties. In a general rate case, the regulator authorizes the rates that a utility could charge its customers. It uses a test year that matches revenues with costs, at least for the first year of new rates.

4 A test year is an actual or hypothetical 12-month period over which a utility calculates its costs, including both operating and capital costs, and revenues to determine the need for a rate change. At the core of a test year is the "matching principle" for achieving consistency between costs and revenues. The utility would thus account for both revenue requirements and billing determinants in setting new rates.

As this paper examines, MRPs come in various versions with different expected outcomes and underlying objectives (e.g., price cap regulation).[5] One extreme example is to set a rate moratorium where rates are fixed for, say, three years. The outcomes of an MRP depend on not only its basic structure but also on its supplemental features and implementation. This paper concludes that strong analytical support exists for MRPs, but regulators need to be aware of pitfalls that can jeopardize their ability to benefit utility customers and advance the public interest. Political considerations might also prevent MRPs from operating at maximum performance in serving customers and the public interest.

Over the past several years, electric utilities have proposed MRPs in a number of states, for example Georgia, Minnesota and Washington. Regulators have applied MRPs in different industries.[6] MRPs are more common in other countries that regulate public utilities.[7] One rationale for MRPs in the U.S. is that they modify the timing and surety of capital cost recovery for new investments. This objective differs from the primary goals found in the economics literature for MRPs, which is to provide utilities with better incentives for cost control and more flexibility in their operations and marketing strategies.

The focus of regulators should be on whether MRPs represent good ratemaking. Since its beginning, state utility regulators have strived to balance different interests for the public good. Regulatory experts generally agree that good ratemaking leads to utilities performing at high economic efficiency, fairness, and reasonable regulatory costs. *Economic efficiency* requires utilities to adopt new technologies when economical, achieve excellent operating performance, and set rates that correspond to marginal cost. *Fairness* means that neither customers nor utility

[5] Under price cap regulation, allowable price changes between general rate cases depend on exogenous input prices and performance benchmarks (e.g., total factor productivity for a peer group of utilities). For example, the maximum price that a utility can charge during a period t equals the base price plus the accumulated changes since the base period, determined by the change in the selected price index (e.g., Gross Domestic product Price Index) minus an X-factor, which commonly relates to a measure of total factor productivity plus a "stretch factor". Price caps have good incentives for high cost performance, but they can lead to a utility earning high profits. In the absence of an earnings sharing mechanism, in other words, a utility's actual rate of return could be much higher than the authorized rate of return. This possible outcome derives from periodic price adjustments based on parameters external to an individual utility's conditions. [One benefit of price caps to customers is that they receive the benefits of productivity growth plus a "stretch factor", as they are built into the allowable rate changes between rate cases.] A tradeoff exists between giving a utility a strong incentive to control its costs and achieving a rate of return that is within a tolerable range of the utility's authorized rate of return. *See*, for example, Mark Lowry and Lawrence Kaufmann, *Price Cap Regulation of Power Distribution*, prepared for the Edison Electric Institute, June 1998; and Wayne P. Olson and Kenneth W. Costello, "Electricity Matters: New Incentives in a Changing Electric Services Industry," *The Electricity Journal*, Vol. 8 (January-February 1995): 28-40.

[6] These industries include railroads, oil pipelines, and telecommunications. *See* Mark Newton Lowry et al., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, prepared for the Edison Electric Institute, 35. In other countries, regulators and other policymakers have usually initiated MRPs.

[7] Ibid, 35.

shareholders unduly shoulder risks or retain the benefits of utility activities.[8] A large part of *regulatory costs* is the expenses the utility and other groups (including the regulatory agency) incur over the course of a general rate case.[9] Frequent rate cases, for example, can impose substantial costs on utility management and regulatory staff resources.

This paper will discuss MRPs from different angles:

1. The rationales for MRPs (e.g., traditional ratemaking creating new problems or magnifying current ones);

2. The different versions of MRPs (e.g., price caps);

3. Why stakeholders have shown more interest in MRPs over the past few years;

4. The contrast between traditional cost-recovery practices, especially for capital costs, and MRPs in terms of mechanics;

5. The advantages and disadvantages of MRPs, compared with other ratemaking options, in achieving different regulatory objectives to advance the public interest[10];

6. Utility incentives under an MRP to control operating and capital costs;

7. How MRPs affect a utility's performance in different areas (e.g., operations costs, reliability, energy efficiency);

8. How MRPs can benefit customers;

9. How MRPs can protect customers from subpar utility performance and utilities earning a rate of return far above the authorized level;

10. The conditions under which MRPs become more justified in setting just and reasonable rates;

11. The different ways to structure MRPs (e.g., core features and add-ons); and

12. How MRPs can hold utilities accountable for costs and other areas of performance (e.g., service reliability).

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[8] Fairness is essential for the public credibility of the regulatory process and regulation itself.

[9] The initial costs of MRPs to regulators and stakeholders may be high.

[10] These alternatives include cost trackers, infrastructure surcharges, and deferred accounting.

II. Features of Traditional Ratemaking

One motive for MRPs is their ability to reduce both the frequency of general rate cases[11] and strengthen utility incentives for cost efficiency. As one example, a major reason for the Washington Utilities and Transportation Commission (WUTC) approving Puget Sound Energy (PSE) multiyear plan was to reduce the frequency of rate cases.[12] PSE agreed to a stay-out period and the Commission in return allowed an annual escalation factor of three percent for certain costs, i.e., an attrition allowance.[13] The WUTC approved a "stretch goal" that required PSE to achieve cost reductions at a rate greater than historically to reach its authorized rate of return. One objective was to challenge PSE to earn its authorized rate of return. The PSE plan also includes an earnings test that has a 50-50 sharing arrangement for utility returns exceeding the authorized return. In its order, the WUTC cited the landmark *Hope* decision by remarking that it is the "end result", rather than the means of getting to it, that is the test for whether proposed rates are just and reasonable. The WUTC also articulated that one objective of an MRP is to provide a utility with good incentives to control costs, which allows it to earn a rate of return above its authorized return. It emphasized that even to earn its authorized rate of return, a utility should demonstrate efficient behavior that saves costs.

In other jurisdictions such as Florida, Minnesota, New Jersey, and Virginia, utilities have pushed for MRPs to facilitate their recovery of capital costs for new investments. Relative to traditional ratemaking, MRPs allow utilities to recover their capital costs earlier without having to file multiple general rate cases.[14] This paper advises regulators to view MRPs from a broader public-interest perspective, taking into account the cost efficiency, "fairness", and other core regulatory objectives.

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[11] In a general rate case, the regulator determines what rates a utility could charge its customers for a future period. That determination relies on a "test year" *estimate* of future utility expenses, sales, and investment, as well as the cost of debt (interest on loans) and the cost of equity (the cost of attracting shareholders), with debt and equity funding the capital projects necessary to fulfill the utility's service obligation.

[12] The WUTC used an adjusted historical test year, rather than a future test year, to set initial-year rates. Washington Utilities and Transportation Commission, *In the Matter of the Petition of Puget Sound Energy, Inc, and Northwest Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entities associated with the Mechanisms, Final Order Authorizing Rates*, Dockets UE-130137 and UG-130138, June 25, 2013.

[13] With price, or average revenue fixed between rate cases, an increase in average cost inevitably leads to the lowering of a utility's earnings or profits. This creates what analysts called *earnings attrition* which makes it less likely that a utility would earn its authorized rate of return beyond the test year. Attrition is more likely under an historical test year but can occur under a future test year when cost increases dominate sales increases to produce a lower rate of return. On the opposite side of the spectrum is the term accretion, which refers to a utility "overearning" between rate cases.

[14] Utilities have proposed other rate mechanisms to facilitate recovery of capital costs, including formula rates and capital cost trackers.

A. The regulatory objective of "just and reasonable" rates

Some proponents of MRPs have contended that they are compatible with setting "just and reasonable" rates and the "balancing act" of regulation.[15] This paper later elaborates on the validity of this argument, which depends on the structure, details, and implementation of an MRP.

For now, an evaluation of the rates established under an MRP, in terms of the universal regulatory mantra of "just and reasonable", involves five major items:

1. Rates reflect the costs of an efficient and prudent utility;

2. Rates reflect the cost of serving different customers and providing different services and different levels of service;

3. Rates avoid undue price discrimination;

4. Rates must be fair among customer groups, and between utility shareholders and customers; and,

5. Rates allow a prudent utility a reasonable opportunity to receive sufficient revenues to cover its cost of capital so as to attract new capital and not encounter serious financial problems.[16]

Overall, "just and reasonable" rates entail giving a utility a fair chance of earning its authorized rate of return as long as it is performing prudently. Some utilities have argued that when attrition occurs they have no reasonable opportunity to earn their authorized rate of return.[17] Other regulatory objectives for ratemaking include public acceptability, rate stability and gradualism, affordable utility service, efficient consumption, efficient competition, moderate regulatory burden, and promotion of specified social goals (e.g., facilitate recovery of capital

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[15] The "balancing act" tries to avoid the extreme positions of parties, whether they are utilities or interveners. It requires regulators to make trade-offs between various ratemaking objectives in reaching an outcome that best serves the general public. For example, although an MRP could help utilities financially, it may expose customers excessively to the risks of forecasting error and bias. Cost trackers also benefit utilities but, in the absence of adequate oversight, can lead to inflated costs that utilities recover from customers.

[16] The U.S. Supreme Court has stated: "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Waterworks v. PSC of WV* 262 U.S. 679 (1923).

Some analysts favor the requirement that if a utility wants to earn its authorized rate of return, it would have to improve its productivity or cost efficiency. This is a more stringent condition for a utility to earn its authorized rate of return and one that stresses the objective of an MRP to enhance a utility's cost efficiency.

[17] Attrition is the result of revenue growth falling short of revenue-requirement growth, causing erosion in the utility's rate of return over time in the absence of a rate change.

costs to promote certain social objectives). Any evaluation of MRPs should entail determining whether they perform better or worse than alternative rate mechanisms in advancing these objectives.

From a legal perspective, regulators must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors in line with actual risks.[18] The emphasis is then on the results reached, not on the methods used. One obvious implication is that the merits of a ratemaking mechanism depend on its likelihood of setting "just and reasonable" rates. Whether rates established under an MRP are just and reasonable is not obvious. As discussed later, MRPs have some downsides that can jeopardize this objective, but other mechanisms have shortcomings as well in achieving just and reasonable rates.

B. The evolution of traditional ratemaking

Traditional ratemaking is the default method that state utility regulators have relied on for decades in setting utility rates. It is also the benchmark used by U.S. regulators to assess other ratemaking practices. Even though some industry observers have written off traditional ratemaking as an anachronism, it remains the core ratemaking paradigm in state utility regulation, notwithstanding the onslaught of alternative rate mechanisms proposed by diverse interest groups over the past two decades.

Typically, the onus is on utilities and other stakeholders to demonstrate the superiority of an alternative approach to traditional ratemaking. A proactive regulator would initiate, or at least consider, other alternative rate mechanisms on its own when conditions change to cast doubt on the efficacy of existing ratemaking methods.

Throughout its history, state utility regulation has had to grapple with finding the "right" ratemaking mechanism that is most compatible with the public good. Back in the late 1960s and 1970s, for example, regulators gave approval to new rate mechanisms and concepts such as future test years, fuel adjustment mechanisms, special rates to certain industrial customers, seasonal rates, construction work in progress in rate base, and phase-ins of new expensive power plants.[19]

One lesson from the past is that regulators do adapt to a changed environment, although cautiously, when discord becomes heightened. They tend to depart from traditional practices, including ratemaking ones, only when continuation of the status quo would disrupt the political equilibrium.[20] Whether regulators/legislatures have supported MRPs for this reason requires

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[18] The U.S. Supreme Court outlined these conditions in its order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[19] Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327.

[20] Two relatively recent examples are revenue decoupling and capital cost trackers. The former mechanism tries to appease those who believe that utilities should promote energy efficiency without being penalized financially.

more detailed study, although it seems that they have. One possible concern triggering MRPs is the frequency of general rate cases that (1) weaken utility performance incentives and (2) place a strain on both the regulator's and utility's resources. Another "distress" situation would be the continuous inability of utilities to earn their authorized rate of return, especially when an efficient utility is engaged in major capital expenditures.

C. Relevant features of traditional ratemaking for evaluating MRPs

Traditional ratemaking has several features that are pertinent to comparing it with MRPs. First, in a general rate case parties closely examine a utility's costs to determine whether proposed rates reflect prudent utility management. While cost disallowances for imprudence are rare, just the threat probably motivates utilities to become less cost inefficient and more mindful of their actions on cost. One of the impetuses for MRPs is that they can motivate utilities to be cost efficient without having to rely on prudence reviews. This is arguably easier to do under an historical test year than a future test year.[21]

Second, the regulator's intent is to give utilities a reasonable opportunity to recover their authorized rate of return, but no assurance that they will. A general practice is for regulators to set rates so that a prudent utility has the opportunity to earn a reasonable (or "fair") return on equity. Under traditional ratemaking, the regulator considers just the first year that new rates go into effect. If the dynamics change, then the expected rate of return would differ from what was expected from the rate case decision. In other words, the regulator cannot guarantee that utilities earn their authorized rate of return. Actual returns, for various reasons, inevitably vary from what is authorized. Reasons may be cost inflation, and sales declines, beyond the test year. Some of them are exogenous to a utility's control while others are subject to utility-management discretion. The regulator's obligation is only to create a reasonable opportunity for utilities to earn the authorized level.

Third, the utility has an incentive to improve its cost efficiency once the regulator sets new rates until the next general rate case. Regulatory lag accounts for this incentive, which is more of a consequence of the impracticability of continuous rate reviews and changing economic conditions than by design. This incentive diminishes in a dynamic environment where utilities frequently file general rate cases. For example, if a utility achieves cost savings in 2016 and files a general rate case in 2017, those savings would normally start to flow back to customers when new rates go into effect. The reason lies with the mechanics of traditional ratemaking in setting the price, not the actual earnings of a utility. To the extent that utilities are able to hold down costs, their earnings and rate of return are higher. Customers do not receive the benefits, however, of lower utility costs until regulators include them in new rates after the next general rate case.

Fourth, rate levels are set based on costs and sales estimates for at most a one-year future period. In the past a utility could absorb unexpected cost increases because of increased sales and revenues relative to those for the test year. Especially during a time, such as now, where sales and revenue growth is much more constrained, a utility may have to file a general rate case

[21] Ken Costello, *Future Test Years: Challenges Posed for State Utility Commissions*, NRRI 13-08, July 2013.

to recover increased cost lying outside the test-year calculation. Low general inflation over the past several years has lessened this possibility, however.

Fifth, base-rate changes require a utility to file a general rate case. Because utilities usually initiate rate cases under traditional ratemaking, they can file for new rates, for example, when their costs rise because of lax management. This ability to file rate cases whenever they like would seem to weaken utilities' incentive to control costs. Such filings are expensive and time-intensive for all participants. Their opportunity costs are the beneficial activities that participants would otherwise engage in the absence of general rate cases. Regulatory staff, for example, could devote more time to workshops and other investigations that focus on important issues (e.g., utility planning, cyber security, distributed generation).

Sixth, outside of a rate case, cost recovery occurs only under restrictive conditions; for example, a large cost item, hard-to-predict costs, costs largely outside the control of a utility. Such recovery normally happens by way of a rider, tracker or surcharge, which can diminish a utility's incentive for cost management. The most common riders apply to changes in fuel costs for electric utilities and purchased gas for natural gas utilities. In recent years, riders have grown to include cost recovery for a wide array of utility functions. Regulators have departed from past practices of approving cost trackers only under "extraordinary circumstances."[22]

Overall, under traditional ratemaking regulators try to balance the interests of different stakeholders in achieving just and reasonable rates.[23] The implication for MRPs is that they should avoid being one-sided, unduly favoring utilities or certain customers and other non-utility stakeholders that would compromise the public interest.[24] Allowing utilities to recover their capital costs without regulatory review would be an imbalanced decision. Authorizing excessive subsidies to promote a certain energy resource would also violate the "balancing act" of regulation.

D. Criticisms of traditional ratemaking

Traditional ratemaking has its problems that MRPs advocates say should disqualify it as the default ratemaking paradigm. As some readers recall, back in the 1990s when the electric

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[22] *See* Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009.

[23] Balancing means that a regulator has reached an equilibrium outcome in which different stakeholders, although not completely satisfied with a decision, are not willing to expend much effort in either the legislative or regulatory arena to contest the decision or to take other major action. One interpretation of balance is the utility having strong incentives to control its costs without earning unreasonably high profits or unable to attract capital or maintain financial health required to make investments that benefit customers.

[24] State utility regulators attempt to balance the rights of utilities and their customers by accounting for three main factors: (a) *legal constraints*—for example, utilities have a right to a reasonable opportunity to be financially viable, and customers have a right to just and reasonable prices; (b) *the regulator's perception of fairness*; and (c) *compatibility with a broader interest.* Regulators try to balance the interests of the different stakeholders with the overall objective of promoting the general good.

industry went through major restructuring, many experts believed that traditional ratemaking would not survive.[25] They thought that price caps or more flexible ratemaking mechanisms would replace it because they were more in conformance with the new market environment; but this did not happen. One reason was that regulators were not willing to give up traditional ratemaking as the basic paradigm, although they were willing to modify it around the edges. In accordance with several electric-industry restructuring plans, regulators require utilities to operate under lengthy multiyear rate freezes. Also in the 1990s, several newly privatized utilities in other countries operated under price-cap and other multiyear rate plans.[26]

The perceived deficiencies of traditional ratemaking have evolved over the years, some of which MRPs are able to address:

1. *Weak incentives for long-term cost efficiency.*

   X-inefficiency, a term used by economists, refers to the situation where utilities waste resources by operating above their cost frontier. While X-inefficiency occurs in

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[25] While several states contemplated restructuring of the electric industry within their respective state boundaries (or known as retail choice), ultimately only 14 states kept retail choice by 2007 and one additional one in the last two years. Also, some of these states limited the number of customers or classes of customers who could avail retail choice. Therefore, all retail choice programs were not the same.

[26] One example of an MRP is the Revenue set to deliver strong Incentives, Innovation and Outputs (RIIO), created by the Office of Gas and Electricity Markets (Ofgem), which is the electricity and natural gas regulator in Great Britain. The RIIO model contains the following features: (a) A detailed set of outputs expected of the utility based on a comprehensive business plan, (b) an 8-year rate plan, (c) explicit incentives for achieving certain performance targets, (d) extensive stakeholder involvement, (e) external benchmarking of costs, (f) a total expenditure concept, and (g) uncertainty mechanisms.

RIIO represents a radically different ratemaking paradigm than what U.S. regulators apply to their electric utilities. It focuses less on the utility's earned rate of return and more on the utility's performance. RIIO uses the mantra "value for money." It incorporates an incentive system with rewards and penalties tied to operational efficiencies, as well as funding for innovation and opportunities for utilities to include third parties in the delivery of energy services. Regulators can use the RIIO framework to monitor a utility's performance in serving its customers. If the evidence shows subpar performance, for example, the regulator could impose a penalty. Likewise, the utility could receive rewards for exceptionally good performance in meeting the needs of its customers. For example, the utility may support a platform that accommodates DG and provide real-time information to customers.

Whether RIIO is feasible for the U.S. is highly doubtful at this time. Would state utility regulators be willing to accept a radically new approach to utility regulation, like the UK has? U.S. regulators typically make changes incrementally rather than boldly. Even if not adopted in the U.S., RIIO contains some commendable ideas that state regulators might want to consider in any new ratemaking approach that they adopt. Especially attractive is the notion that a primary criterion for utility revenue is its correlation with *the value that customers receive* from utility service. Benchmarking, which state utility regulators rarely do, rightly shifts the focus from inputs to outputs and holds utilities accountable for subpar performance. *See*, for example, Peter Fox-Penner et al., "A Trip to RIIO in Your Future," *Public Utilities Fortnightly*, October 2013: 60-5; and Ofgem, "Handbook for Implementing the RIIO Model," October 4, 2010.

every industry, it is probably more severe in utility industries by the fact that utilities lack the strong incentives of non-regulated firms to control costs on a sustainable basis. From a long-term perspective, traditional ratemaking resembles a cost-plus contract. [27]

2. *Weak incentives for innovation, especially under tight price regulation.*

   Tight regulation means that changes in rates occur soon after a utility's costs change, allowing the utility little opportunity to profit. Various features of public utility regulation affect how much and how utilities make R&D/innovation investments. They include regulatory commitment, degree of information symmetry, cost recovery, allocation of the benefits, and risk incidence. For example, depreciation policy can help ensure recovery of invested funds over the economic life of the physical capital. The economics literature has devoted relatively little attention to regulated firms' incentive to engage in R&D, and develop and adopt new technologies. Nevertheless, the conventional thinking is that regulation tends to make utilities cautious about innovating and taking risks. Utilities therefore fall short in their R&D activities and deployment of new technologies.[28]

3. *Fixed base rates between general rate cases, which strengthen incentives for cost efficiency but its rigidity could result in extremely high or low rates of return under dynamic conditions.*

   Base rates under traditional ratemaking have two characteristics: (a) the regulator sets them in a formal rate case, and (b) they remain fixed until the utility files a new rate case and the regulator makes a subsequent decision. The costs represent those calculated for a designated test year and exclude those costs recovered in trackers and other mechanisms. Under traditional ratemaking, no matter how much the actual utility's costs and revenues deviate from their test-year levels, base rates remain fixed until the regulator approves new ones in a future rate case. The exception is when a regulator allows for interim rate relief under abnormal conditions that jeopardize a utility's financial condition.

   A utility's costs can vary radically from year-to year, for example from ongoing capital expenditures and large unexpected costs such as from severe storm damage, jeopardizing its ability to earn the authorized rate of return or allowing it to earn an excessively high rate of return.

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[27] *See* Harvey Leibenstein, "Allocative Efficiency vs. 'X-Efficiency,'" *American Economic Review* 56 (June 1966): 392-412; and Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation," in *Handbook of Industrial Organization, Volume II*, Richard Schmalensee and Robert D. Willig, eds., 1449-1506 (New York: Elsevier Science Publishers, Inc., 1989).

[28] *See* Elizabeth E. Bailey, "Innovation and Regulation," *Journal of Public Economics*, Vol. 3 (August 1974): 285-95; and Stanford V. Berg and John Tschirhart, *Natural Monopoly Regulation: Principles and Practice* (Cambridge, UK: Cambridge University Press, 1988).

4. *Excessive regulatory lag, for example under conditions of new investment needs and stagnant sales growth, that makes it hard if not possible for utilities to earn their authorized rate of return.*

   Regulatory lag can either benefit or harm utilities, depending on whether average cost is decreasing or increasing relative to average revenue. [Average cost is a utility's total cost divided by billing determinants such as sales volumes. It therefore rises with cost inflation and lower sales.] Over the history of state utility regulation, regulatory lag has benefited utilities during some periods while hurting them in other periods. For example, utilities generally benefit when prices remain fixed over several years while their average cost is declining. Regulatory lag can cause severe cash-flow problems for utilities. If the costs are substantial and utility recovery of those costs occurs several years after they incurred, they can weaken a utility's financial condition to increase its cost of capital or make it more difficult to attract capital. Problems from delays in a utility's recovery of capital costs for large projects could also jeopardize its cash flow and financial viability.

5. *Regulatory lag deferring the benefits of efficiency gains to customers.*

   Customers benefit from cost savings only after the new base rates go into effect. If a utility, for example, does not file a general rate case for several years, it has strong incentive for controlling its costs. Customers are deprived, however, of the benefits for an extended period, which actually occurred for electric utilities until around the late 1960s.

6. *High regulatory costs.*

   The regulatory costs of traditional ratemaking include the expenses incurred by utilities, interveners, and regulators for rate filings, rulemakings, and other matters falling under regulatory jurisdiction. Traditional ratemaking requires regulators to have access to a great deal of information, which they demand from utilities, for making informed decisions. The difficult job for regulators is to take the conflicting information provided by different parties, "unscramble" it, and ultimately reach a decision balancing the welfare of the various interest groups.

7. *Frequent rate cases in a dynamic environment (i.e., a changing relationship between revenues, costs and rate base) where the utility's average cost increases.*

   Average cost increases whenever the combined growth in input prices and levels exceeds the growth in billing determinants such as sales volumes. Under a condition of moderate to high inflation, large investments in new facilities and slow sales growth, average cost would likely rise. Average cost equals total cost divided by billing determinants. Total cost, in turn, equals the sum of the product of input prices and input levels.[29]

8. *Rigid prices that preclude a utility from offering discount or special rates to certain customers dictated by market conditions.*

   Pricing rigidity prevents a utility from responding in a timely fashion to changing market conditions. These conditions can arise from general inflation, new technological developments, and changes in the intensity of competitive forces and in consumer demand. Allocative inefficiencies result because of effective prices moving farther away from marginal costs and consumers' willingness to pay for utility service.

9. *Cost-shifting and affiliate abuses that are more likely to occur when utilities operate in mixed competitive-non-competitive markets (e.g., a regulated utility that has an affiliate selling coal in the open market).*

   This suggests that price caps may be attractive to regulators if only because of their ability to mitigate these problems.[30]

10. *Incentive for excessive capital investments, under certain conditions (e.g., the Averch-Johnson effect).*[31]

11. *Disincentive to embrace cost-effective energy efficiency, peak demand management, distributed generation, and other distributed energy resources (DER).*

E. Four primary goals of ratemaking

Regulators have assigned four major objectives to ratemaking:

1. Foster economic efficiency;

2. Ensure that a prudent utility is financially healthy;

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[29] Expressed differently from rearranging terms,

Average Cost (AC) = price of inputs/total factor productivity

Thus, % ΔAC equals % Δ price of inputs minus % Δ total factor productivity, or % Δ price of inputs plus % Δ inputs minus % Δ output. As an example, if input prices increase by an average three percent, input levels by one percent and output by two percent, average cost would rise by two percent.

[30] There is evidence that this partly explains the widespread use of price caps in the U.S. telecom industry.

[31] What analysts call the Averch-Johnson (A-J) effect says that a utility would use excessive capital input relative to other inputs such as labor, fuel, and materials. This outcome assumes that a utility faces a binding rate-of-return constraint on its rate base and its allowed rate of return exceeds its actual cost of capital. *See* Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-69.

3. Achieve fairness not only between utility customers and shareholders, but also among the different customer classes; and,

4. Advance social objectives or public benefits.

Economic efficiency takes into account: (a) the cost to society from satisfying the demands of utility consumers (i.e., productive efficiency) and (b) the value that consumers place on utility service (i.e., allocative efficiency). Key actions for achieving economic efficiency are setting rates based on marginal cost principles, and providing utilities strong incentives to operate efficiently. Economic efficiency involves maximizing total net economic value, while equity or fairness involves the distribution of net value among producers and consumers. Another way to look at the two concepts is that what matters to economic efficiency is maximizing the size of the pie, while equity or fairness cares about the slicing of the pie. Ratemaking involves treating these two concepts interdependently as maximizing the size of the pie requires efficient pricing to consumers, which inevitably encompasses slicing the pie as well. MRPs have a more direct effect on the latter component, which is discussed in a later section of this paper.

To ensure that a prudent utility is financially healthy may require that a utility recovers its capital costs in a timely manner to avoid severe cash-flow problems. It may also involve regulators making some sort of commitment to a utility's capital project so as to moderate risk to the utility. Regulatory commitment can be full, partial or none. Partial may involve, for example, the regulator pre-approving a capital project. Any imprudence in utility decision-making affecting completion of the project is still subject to disallowance. Completely eliminating the risk to utility shareholders would tend to overly blunt utilities' incentive to contain the costs of projects and carefully evaluate their economics. In general, regulators typically satisfy their duty to protect customers from excessive costs through substantial oversight of capital projects and the traditional regulatory prerogative to examine a utility's books and management and potentially disallow imprudently incurred costs.

To achieve fairness has to be not only between utility customers and shareholders, but also among the different customer classes. The term "fairness" and its derivative, "fair," appear commonly in regulatory circles. We often hear of a "fair rate of return," "fair and reasonable rates," "fair value," and a "fair process." Because fairness is elusive and enters the domain of philosophy, it becomes difficult to know what is fair and to say that one action is fairer than another is.[32] Since stakeholders perceive fairness differently, the regulator's job is to balance them so as to best advance the public interest. Balancing interests may satisfy the regulator's own interests (e.g., achieving political equilibrium), rather than the public interest. Achieving this goal may result in regulatory approval of a ratemaking mechanism that shares features of different mechanisms. One example is an MRP that contains an earnings sharing component.

Advancing social objectives or public benefits are relatively recent and not presently universally accepted as legitimate objectives to be pursued by state utility regulation. They can include energy efficiency, affordability, and clean energy.

[32] It is probably easier to know when something is unfair, at least from a preliminary reaction.

F. Widespread interest in new ratemaking mechanisms

The recent surge of new ratemaking mechanisms stems from shortcomings of traditional ratemaking like those we previously discussed. The relevant question for regulators is: Should regulation change around the edges or at the core?[33]

Much of the push for non-traditional rate mechanisms such as MRPs comes from stakeholders (e.g., utilities, environmentalists, consumer advocates) with diverse interests.[34] While some economists find MRPs appealing, its strongest supporters in the U.S. have been utilities. It does not seem to be so much because utilities desire stronger incentives for cost efficiency, which certain MRPs can provide; but more because they prefer fewer rate cases, more prompt recovery of cost, especially capital costs.[35] Some utilities view new market and operating conditions, for example, rising average costs and the slowdown of demand growth, as *prima facie* reasons for MRPs.

Utilities would find MRPs especially appealing in that they are forward looking and reflect a multiyear commitment by regulators. They can involve regulatory preapproval of capital projects and accelerated recovery of capital costs. This gives utilities greater certainty over cost recovery. Whether or not this benefits utility customers in the long run is the question that regulators should ask.

G. Current status of MRPs

Interest in various variations of MRPs has slowly spread across states. Conditions are favorable to MRPs, specifically with low or no growth in sales for electric utilities along with increasing demand for capital expenditures. According to one study by Lowry and Woolf,

> In the U.S. electric utility industry, MRPs [multiyear rate plans] were first used extensively in California, where a Rate Case Plan was established in the 1980s that, with modifications, has limited the frequency of general rate cases to this day. Iowa, Maine, Massachusetts and New York have also been MRP innovators. An MRP for Central Maine Power afforded the company considerable flexibility in marketing to price-sensitive paper mill customers. MidAmerican Energy operated under a lengthy rate freeze that extended to its energy costs but permitted the company to keep margins from its off-system sales. The use of MRPs in the United States has recently spread to

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33 Incidentally, throughout the history of public utility regulation, stakeholders have petitioned commissions to revisit old rate mechanisms and consider new ones (e.g., late 1960s and early 1970s).

34 Added regulatory objectives over the past three decades have included the advancement of energy efficiency and renewable energy, and utility service affordability.

35 Although utilities may argue that an MRP being proposed would improve cost efficiency, their motivation seems to lie more with improving their financial condition.

vertically integrated utilities in a diverse collection of other states that includes Colorado, Florida, Georgia, Virginia and Washington.[36]

Recent studies and other investigations have examined different forms of MRPs, such as rate freezes, revenue caps, formula rate plans[37], and price caps. While the evidence from these mechanisms do not indicate any serious problems, most utility regulators appear reluctant to part with traditional ratemaking, which determines rates solely from a test year.

[36] Mark Newton Lowry and Tim Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future*, LBL-1004130, January 2016, 30.

[37] Formula rate plans can function as a safety net for regulators by preventing utilities from earning extremely high or low profits between formal rate reviews. They do this by adjusting base rates between general rate cases, which in that sense falls under the meaning of an MRP. Also like some other MRPs, formula rate plans specify how a utility can change its base rates for periods beyond the rate effective year. A utility can adjust rates, for example, when its rate of return fall outside some predetermined range. Some analysts place formula rate plans outside the category of MRPs. One study, for example, considers a formula rate plan as a comprehensive cost tracker. Ibid., 9. *See* also *supra* note 6. Other analysts would contend that formula rates differ fundamentally from MRPs.

Formula rate plans can allow customers to benefit visibly and directly when conditions favor a utility to earn high profits. Economic analyses have shown that compared to a pure price-cap regime, earnings-sharing-type mechanisms may better improve the long-term economic welfare of consumers. [*See*, for example, Richard Schmalensee, "Good Regulatory Regimes," *Rand Journal of Regulation* 20 (Autumn 1989): 417-36; and Thomas P. Lyon, "A Model of Sliding-Scale Regulation," *Journal of Regulatory Economics* 9 (May 1996): 227-47.] Formula rate plans attempt to balance both an economic and political test, which pure price-cap regulation does not attempt to do. Some regulatory plans in the U.S. add an earnings-sharing component to an MRP, which try to give utilities strong incentive for cost efficiency while placing bounds on their profits. These bounds recognize the possibility that a utility can earn extreme profits that can conflict with both "equity" and political standards. The challenge in structuring earnings sharing is to not seriously diminish the utilities' cost efficiency.

III. Objectives of MRPs

A common motive for MRPs is to reduce regulatory cost and improve the regulatory process.[38] The presumption is that under traditional ratemaking utilities would file continuous rate cases because of their costs growing faster than sales.

A. Utility perspective

Supporters of multiyear rate plans in the U.S., typically utilities, point to six benefits:

1. More predictable revenues for utilities, bolstering their financial health;
2. Spreading of rate increases over a longer period;
3. More predictable rates for customers;
4. Stronger performance incentives;
5. Timely recovery of costs for new capital projects; and
6. Fewer general rate cases over time.[39]

These benefits, although at first glance they may not seem terribly impressive from the perspective of utility customers, can dominate any downsides, making multiyear rate plans worthwhile to consider.

Supporters contend that MRPs avoid "earnings" attrition by preventing the erosion of a utility's rate of return that could occur under an historical test year with the past relationship between revenues, expenses and rate base not relevant for the future. Some proponents of MRPs argue that since they ease the financial burden on utilities when they invest in new infrastructure, customers stand to benefit in the long run.[40]

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[38] It is imperative that a more efficient regulatory process does not compromise transparency and oversight. By shortcutting certain regulatory activities, for example, the regulator may be slighting some activities that are essential to its duty. One prime example is rubber stamping some costs that the regulator should expend time in reviewing their prudence. An alternative is for the regulator to provisionally allow a utility to recover all of its costs but then in, say, the next general rate case perform a prudence review. One practical problem is that several years may have passed between when the utility made the expenditures and when the regulator carries out the prudence review.

[39] Regulators do not like frequent rate cases: They expose regulators to public scrutiny and confront them with the difficult task of balancing the interests of politically charged stakeholders. Besides, rate cases are time consuming and expensive, leaving the regulators with less resources to pursue other activities integral to their duties. Another negative effect from frequent rate cases is that they tend to diminish the incentive of utilities to control their costs, since the benefits to them get more quickly passed on to customers.

[40] *See*, for example, Toby Brown et al., "Incentive-Based Ratemaking: Recommendations to the Hawaiian Electric Companies," prepared for the Hawaiian Electric Companies, May 20, 2014, 23.

From a utility's perspective, the biggest benefit from MRPs probably comes from an improved opportunity to earn its authorized rate of return. That is, the mitigation of regulatory lag that can jeopardize a utility's financial health

In a dynamic environment, utilities also find appealing that MRPs allow their revenues to change in post-test years to reflect the costs of new investments and other additional expenses between rate cases. That is MRPs allow more prompt recovery of costs associated with investments. Otherwise, as some utilities have argued, they would be hard pressed to earn their authorized rate of return between rate cases.

B. Improving utility performance

From a public-interest perspective, the most positive aspect of MRPs derives from improving utility performance, which goes beyond a utility's financial health.[41] After all, regulation has an obligation to induce high-quality utility performance, whether it is customer service, physical operation of the utility system, service reliability, cost controls, or the adoption of new technologies. The economics literature shows that public utilities left unregulated, or regulated ineffectively, would perform poorly. They would set prices too high, price discriminate among customers, provide an inferior quality of service, deploy a nonoptimal mix of inputs, and devote deficient effort to control costs and innovate.[42]

MRPs have the potential to enhance utility performance through different means:

1. *For a utility to earn its authorized rate of return, the regulator could require the utility to improve cost efficiency*: The Washington Utilities and Transportation Commission, for example, agreed in a settlement that Puget Sound Energy should achieve lower-than-historical cost increases in certain categories to earn its authorized rate of return.[43]

2. F*acilitation of cost recovery for capital projects can mitigate a utility's disincentive to make socially desirable investments and has other benefits to customers*: By spreading capital cost recovery over a longer period of time than what is the traditional practice, an MRP can also mitigate rate shock[44], lower a utility's risk, improve utilities' cash flow during construction, and avoid delays in capital cost

[41] Utility performance derives from two distinct factors: *internal efficiencies and external conditions.* The first factor encompasses utility competence in combining and deploying labor, capital, and other resources to manage performance. The second factor accounts for market, operational, business, and other conditions over which an individual utility has minimal control.

[42] See, for example, *supra* notes 27 and 31.

[43] *Supra* note 12.

[44] An MRP, for example, can levelize rate changes by spreading a $100 million rate increase over three years instead of placing all of it in the rate-case test year, which begins soon right after the end of a rate case. Rate moderation mechanisms, however, only defer and do not eliminate the need for rate relief. Customer frequently have to pay the utility a carrying charge for stretching cost recovery out over time to achieve more stable year-to-year rate changes.

recovery; these investments can include supporting DER and other new technologies that would benefit utility customers and are compatible with state or federal energy policies.[45]

3. *An automatic rate adjustment mechanism not linked to a utility's actual cost changes can motivate it to achieve higher cost efficiency*: In setting revenue requirements beyond the test year, utilities can either rely on forecasts of their actual costs or use an index for determining allowable cost changes in rates. Because the index does not track a utility's actual cost changes, the utility benefits financially when it achieves cost changes below the index level. For example, if an index for O&M costs allows a utility to increase its revenues by a certain amount, the extent to which the utility "beats" the index, it profits at least until the general rate case.

4. *Performance metrics to evaluate and take appropriate action can provide utilities with an added incentive to improve their performance in non-cost functions*: Most MRPs in operation contain separate performance metrics to ensure customers that a utility has not allowed its performance in reliability or customer service to deteriorate during the course of an MRP.

5. *Price flexibility, which some MRPs allow, gives utilities the ability to vary their price to different customers based on economic and other circumstances.*

6. *A "fair" share of benefits from improved utility performance between the utility and its customers can occur before the next general rate case*.

From a regulatory-process perspective, MRPs can help consolidate different rate mechanisms, making it more efficient and holistic/systematic. A utility could eliminate some riders and surcharges, as certain costs are recoverable under an MRP whereas they were not previously. Riders, where a utility can recover cost changes for certain items outside of a rate case, can cause problems.[46] By including these costs in base rates, they are likely to receive closer regulatory review, and utility incentives for managing them become more compatible with other costs.

MRPs can also avoid "extreme" utility financial outcomes. By including an earnings-sharing component, they can confine a utility's actual earnings within a tolerably acceptable range. The structure of earnings sharing affects a utility incentive for cost control; a poor structure, for example, could lead to cost-plus-type incentives that would tend to inflate a utility's costs and be detrimental to utility customers.

Finally, as contended by some observers, MRPs can bolster a utility's incentive for supporting energy efficiency and DER.[47] For example, by limiting revenue changes over a

[45] *See supra* note 36.

[46] *Supra* note 22.

[47] *Supra* note 36.

multiyear period, an MRP can motivate a utility to focus less on increasing sales and discouraging customers from self-generation.[48]

[48] The intent is to steer utilities away from allowing utilities to profit from increased sales and capital expenditures and toward maximizing value that their customers receive from utility services.

IV. Core and Add-On Features of MRPs

MRPs have a core structure supplemented by secondary features or add-ons. This section will identify and discuss them. MRPs come in different forms depending on such factors as their objectives, the political landscape, and the bargaining strengths of the various stakeholders. In the U.S., MRPs for utilities tend to reflect compromises that make them less than ideal from a theoretical perspective, for example, in terms of maximizing a utility's incentive for cost efficiency.

A. Core structure

The primary structure of MRPs has three components. The first is the starting base rate or revenue, which derives from test year cost and revenue statistics. Most plans use a future test year. Alternatives include an historical test year and a benchmarking method[49] that reflects the costs of an efficient utility.

As an illustration, an historical test year (HTY) could be 2015, in which the utility would have actual data for the 12-month period. An HTY uses data for a 12-month period that ends prior to a rate filing. In contrast, a partially future or hybrid test year could cover the last six months of 2015 and the first six months of 2016. A future test year (FTY) could be the calendar year 2017. An HTY uses only costs and sales statistics that are known and measurable, unlike a FTY that uses estimates. The tradeoff is that while an HTY uses exact data, it may reflect poorly the conditions during the period over which new rates are in effect. Even if the utility makes *pro forma* adjustments to historical data, in practice they are usually limited to known and measurable changes.

The second component relates to changes in base rates or revenues outside the test year. This is where MRPs are most distinct from traditional ratemaking. A utility can apply detailed cost forecasts or escalation factors attached to the base rate or revenue. An escalation factor acts as an attrition adjustment. An MRP can allow rate changes to be independent of actual cost changes. As discussed later, this gives utilities an incentive to control their costs. Alternatively, rate changes can be a function of a predetermined amount (or value); for example, an amount forecasted during the previous rate case. Forecasts can derive from detailed cost of service analysis, a utility's budget, or a combination of both.

The third component is the duration of an MRP. When an MRP predetermines the time for a future general rate case, the length of regulatory lag becomes known to the utility and other

[49] The generic definition of *benchmarking* is the comparison of an individual utility's performance against some predefined reference (e.g., peer group). This definition focuses on outcomes, for instance the services provided by a utility per unit of labor or capital, or the level of reliability. An alternate definition of benchmarking would center on a utility's practices and uses of different technologies: Has the utility adopted "best practices" in the form of state-of-the-art technologies and management processes?

stakeholders.[50] The longer is the duration the more incentive a utility has to control its costs.[51] The duration determines the length of regulatory lag, which affects both cost incentives and the likely range of a utility's rate of return until the next general rate case. A longer duration would tend to increase the likelihood that a utility's rate of return will fall within a wider range.

B. Add-ons

1. Optional but important

The noncore elements of an MRP are practical features needed for political acceptability and the prevention of "extreme" outcomes that might jeopardize the future of an MRP. One reason for add-ons is to protect customers from outcomes during the duration of the plan that were not anticipated at the beginning of an MRP. Such outcomes can include poor performance in service quality, exceptionally high rates of return, grossly forecasted capital costs, and imprudent utility costs. Examples of protections are refunds for an excessive rate of return, caps on recoverable capital costs, monitoring of utility performance, and detailed audits to determine appropriate cost recovery.[52]

One common component of MRPs is performance metrics for non-cost utility functions, such as reliability and customer service.[53] A concern is that utilities under an MRP may jeopardize the quality of its service in the process of controlling costs to increase their rate of return. Some MRPs have performance standards or incentives for service quality and other outcomes.[54]

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[50] Sometimes the end of an MRP may not predetermine the timing of the next rate case. Utilities have been able to have an MRP end and stay out of a rate case. Central Maine Power is one example of such a utility

[51] Regulatory lag is a less-than-ideal method for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). Experience has shown that state utility regulators are more receptive to mitigating regulatory lag when it causes a substantial downward movement in a utility's rate of return between rate cases. This in part explains the proliferation of trackers and surcharges in recent years.

[52] Utility cost recovery in the absence of regulatory oversight would ostensibly (a) be unfair to customers and (b) create a "moral hazard" problem that diminished a utility's incentive to manage its costs.

[53] Developing metrics can be particularly challenging.

[54] When the utility receives additional revenues from higher performance, a natural question is what benefits go to customers. Do these benefits at least cover the additional revenues that customers have to pay the utility? Do the benefits of improved performance to customers, for example, coincide with the additional revenues to the utility? Although in many instances the benefits to consumers are non-quantifiable, the regulator should be able to make an informed decision on whether the benefits to consumers from improved utility performance correspond to the additional revenues that the utility receives. The problem with customer benefits falling short of additional revenues is that the utility receives a windfall gain in its profits at a cost to customers.

The following is a litany of add-ons that regulators have either approved or required:

1. "Off-ramps" (i.e., conditions for plan suspension or termination);

2. Cap or floor ("collar") on annual rate increases;

3. Earnings test;

4. True-ups/deferrals[55];

5. Stay-out period;

6. Refunds to customers (e.g., from an unexpected cancelled or delayed capital project; from imprudent utility costs identified by an *ex post* review)[56];

7. Rate design as part of an MRP[57];

8. Efficiency carryover (e.g., counter ratchet effect[58]); and

9. Utility pricing flexibility (designating a price floor and ceiling)

2. Discussion

Under traditional ratemaking, the utility receives the benefits of "exceptional" performance between rate cases. The earnings test can allocate some of those benefits to customers prior to the next rate case.[59] It can prevent the utility from earning an extremely high or low rate of return. The biggest challenge with earnings sharing is to avoid compromising a utility's incentive to control costs. The essential features of earnings sharing are the dead band

[55] True-ups and earnings tests can substitute for each other in the sense of protecting customers from excessive utility profits because of inaccurate or biased forecasts.

[56] Such refunds would have to fall outside the realm of retroactive ratemaking.

[57] The general rate case can address issues related to rate design and cost allocation in addition to the revenue requirement. This is one reason for why the duration of an MRP should have an upper limit, say, three to five years.

[58] What analysts call the ratchet effect affects the resetting of rates at the next general rate review (i.e., prior actual outcomes affects future rate determination). If the utility knows that the regulator will use the information about its realized costs as a factor in resetting future rates, this will affect its behavior *ex ante*, as discussed later. The utility may have an incentive, for example, to engage in less cost reduction to mislead the regulator into thinking that it is a high cost utility in the latter years of an MRP so that it can justify a higher new base rate or revenues.

[59] Reasons for excessive/deficient earnings include (a) abnormal costs and revenues from temporary factors like high inflation, a slowdown in the economy, weather), (b) normal costs and revenues differing from levels used in setting base rates in the last general rate case because of systematic forecasting problems like forecasts of normal levels susceptible to large error and inaccurate forecasting, and (c) exceptionally good or bad utility-management competence.

region[60], the sharing ratio, and the post-adjustment rate of return relative to the authorized return.[61] Regulators should avoid resetting annual rates based on a utility's actual cost in the absence of a prudence review, and on its authorized rate of return in the last general rate case.

Regulators generally apply a three-part test for expense deferral: (1) the cost is material and extraordinary in nature, (2) the cost was incremental to what was allowed in rates, and (3) the utility is not over-earning. Regulators should have strict guidelines on what costs a utility can defer.

As a matter of policy, true-ups should only apply to those expenses that are difficult to forecast and over which the utility has little or no control. Customers receive protection when actual expenses are less than forecasted and the utility receives protection when actual expenses exceed the expected level. A key challenge for the regulator is to determine when the utility should have reasonably foreseen the variance.

In line with theory, some evidence shows that utilities tend to aggressively reduce costs during the early part of an MRP but then to inflate costs at the end of the plan so as to better justify a higher revenue requirement for the plan's next cycle.[62] Efficiency carryover would mitigate this in addition to allowing utilities to retain for a longer period the benefits of superior performance; or to absorb for a longer time the costs associated with inferior performance, each of which would strengthen their incentive to control cost. Efficiency carryover works by truing-up the revenue requirement in the next rate case at less than 100 percent.

"Off-ramps" gives the regulator the discretion to terminate or amend an MRP when things go really bad.[63] It acts as a safety net, but one that regulators should exercise with caution. By excessively relying on "off-ramps" when outcomes are less than satisfactory, regulators create an aura of uncertainty that could jeopardize a utility's behavior to control costs and take other actions that are in the public interest. The same outcome could come from a utility filing an interim rate case during the MRP period when its rate of return drops to what it

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[60] The dead band determines the range of the rate of return within which no rate adjustment takes place. It recognizes the effects of unexpected outside factors or random events on the actual rate of return. Within this range, the utility has strong incentives for cost efficiency similar to that under traditional ratemaking between general rate cases. In theory, the range should include: (a) a lower value that does not place the utility in a "difficult" financial situation and (b) a higher value that does not reflect "exorbitant" earnings for the utility.

[61] In sharing the earnings outside the dead band region, the utility might adjust rates to bring the rate of return to either the "boundary point" or the authorized rate of return (e.g., the midpoint of the band). These adjustments provide the utility with less robust incentives for cost efficiency than if the regulator adjusts rates so that the utility earns a return outside the dead band region. The tradeoff is that the utility is more likely to experience financial problems, or is able to retain a higher share of the gains from superior cost efficiency.

[62] Paul L. Joskow," Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks," working paper, January 21, 2006, 15.

[63] The regulator may subsequently reset rates to whatever level it deems just and reasonable.

would consider a critically low level. A stay-out provision would avoid this by prohibiting a utility from requesting an adjusted rate change for the duration of a plan.

V. Specific Issues for Regulators

A. Articulating a rationale

State utility regulators should articulate their rationale for supporting MRPs. One rationale is that traditional ratemaking makes it improbable for a utility to recover its prudent costs. Beyond a future test year, for example, attrition may erode a utility's rate of return to an unacceptable level.[64] Using this rationale solely says that regulators should support an MRP only when there are unusual, extraordinary, and significant concerns about cost recovery.[65] This view seems excessively narrow, since other reasons can justify MRP as a ratemaking mechanism that has the potential to benefit utility customers and the public at large. These reasons include lowering of regulatory costs, increased incentives for cost control from less frequent general rate cases, and moderate rate changes compared with one-time large increases. Another rationale that utilities have stressed is that MRPs would allow for more timely recovery of capital costs for new investments, which could benefit customers in addition to themselves.

One issue is whether regulators should establish regulatory guidelines or standards to articulate their criteria for reviewing and approving an MRP. Guidelines can steer utilities and other stakeholders toward particular aspects of an MRP that the regulator would view as either favorable or unfavorable. A regulator can convey its views on MRPs in a policy statement, rules and regulations, or an order. Each of these has different effects. A policy statement, for example, has less import than rules, but it still can be effective in reducing the uncertainty over how a regulator would respond to a particular proposal for an MRP.[66]

Regulators should demand that utilities justify an MRP proposal over alternative ratemaking mechanisms. For example, a utility could articulate the advantages that an MRP has over alternative approaches in addressing the underlying problems with traditional ratemaking.

B. What are the issues?

MRPs pose several questions for regulators, some being more difficult and more important to address than others. The major ones are:

1. Length of the multiyear period;

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[64] A future test year uses projections of costs and revenues usually over a twelve-month period during which new rates would apply, as the basis for determining the annual revenue requirement. If the projections are accurate, and if costs continue to grow more than sales do, a future test year compared with an historical test year would increase the likelihood of a utility earning its authorized rate of return. It achieves this outcome by reducing regulatory lag.

[65] A counterargument is that if utilities believe that they will under-earn in the near future, they can always file a rate case. Because utilities initiate rate cases under traditional ratemaking, they can file for new rates, for example, when their costs rise because of lax management. This ability to control the timing of rate cases would somewhat weaken utilities' incentive to control costs. S*ee*, for example, Ellen M. Pint, "Price-Cap versus Rate-of-Return Regulation in a Stochastic-Cost Model," *RAND Journal of Economics*, Vol. 23, No. 4 (Winter 1992): 564-78.

[66] A policy statement also may not bind a future commission.

2. Base period revenues and costs;

3. Allowed costs in base rates;

4. Focus on rate changes or revenue changes;

5. Attrition allowance for post-test year rates or revenues;

6. Cost escalation by forecasting or indexing[67];

7. Conditions for recovery of capital costs[68];

8. Capital cost included in MRP (e.g., actual, projected)[69];

9. Adjustments to customer charge or volumetric charge;

10. Inclusion of a "stretch factor" (e.g., motivating a utility to achieve higher cost-efficiency than in the recent past);

11. Additional rate adjustments during a multiyear period (e.g., true-ups for individual costs, earnings sharing[70]): rationale[71]; and

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[67] As expressed by one Minnesota utility:

> A fundamental consideration of any MRP [multiyear rate plan] proposal is whether rates will be established for each year of the plan within the rate case or, alternatively, a formula (or annual adjustment mechanism) will be established in the rate case by which rates can be adjusted for each year of the multiyear period based on a set of predetermined inputs. While both approaches have merit, the Company recommends that the Commission allow the latter approach because it may provide the greatest amount of benefits to stakeholders in the regulatory process, including customers. While multiple forecasted test years could be used to establish rates for each year of an MRP during a rate case, determining a formula by which rates will be set for each year of the MRP could be administratively more efficient. Nevertheless, the determination of whether an MRP establishes rates for each year of the plan at the time of the general rate case or instead sets a formula to calculate the annual MRP rate adjustments should be made based upon the specific needs, business environment, and MRP proposal of each individual utility.

[CenterPoint Energy, *Comments of CenterPoint Energy, In the Matter of the Minnesota Office Of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards For Multiyear Rate Plans under Minn. Statute §216B.16, subd. 19; Docket No.: E,G999/M-12-587*, October 15, 2012, 8.]

[68] For example, should a utility be able to recover capital costs for a project during the duration of an MRP even if the in-service date falls beyond the last year of the MRP?

[69] An MRP allows a utility to recover capital costs based on a formula, a budget forecast or a fixed escalation rate, or a combination of these factors.

[70] Earnings sharing can allow customers to share in the benefits of lower utility costs earlier in time. It has the problem of weakening a utility's incentive to control costs.

12. Adjustments to the authorized rate of return (e.g., for reduced risk imposed on the utility and accelerated utility recovery of capital costs) and changes in the rate of return during the course of a plan[72].

C. Discussion of major issues

1. Procedural questions

One fundamental question is whether a utility has the discretion to use an MRP, or whether the decision is solely in the hands of the regulator. Should an MRP, for example, be relied on as a ratemaking tool only as a last resort? One sensible view is that regulators should have the discretion to choose the test year, assuming they have the authority. The preferred ratemaking mechanism, whether traditional ratemaking or an MRP, from a public-interest perspective depends on the actual utility's conditions.

Why should regulators allow utilities to select the ratemaking mechanism when they should expect a utility to choose one that best advances the utility's interest rather than the public interest? What happens, for example, if a utility proposes an MRP and the regulator's staff believes it is incapable of evaluating the forecasts? In this instance, the utility would have a distinct incentive to inflate its costs and hopes that the regulator would not detect it. This utility prerogative is akin to allowing the utility to choose rate design or a cost-of-service methodology, with the regulator relegated to a secondary role in fine-tuning a proposal. Most regulators would understandably find this status unacceptable. Legislatures threaten the independence of regulators, and overstep their authority, when they mandate the use of a specific ratemaking mechanism, no matter the circumstances or actual conditions that a utility faces.

Another issue is the filing requirements for an MRP proposal. Should an MRP be part of a rate case, or a separate proceeding? The last alternative may be appropriate, for example, when a utility requests recovery of costs for a major capital project. In its filing, a question is whether post-test year revenues should derive from a detailed cost of service analysis or just represent incremental changes from test year costs.[73] In Minnesota, for example, the Public Utilities Commission ruled that during the second and third years of an MRP, utilities can recover costs

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[71] Reopeners can occur as a request for recovery of "certain, limited cost items" (like in Wisconsin) in a streamlined filing, or as a full-rate-case-type filing (like in Minnesota). One criterion for reopeners is extremely high or low utility earnings resulting from factors beyond management control.

[72] Does the use of an MRP, for example, have any material effect on a utility's current risk compared to its peers? One argument is that a utility's cost of capital would decrease because of the reductions in regulatory lag and cost-recovery risk for the utility.

[73] Where MRPs involve forecasts, utilities should provide complete documentation to allow a thorough review by the regulator's staff and interveners of the forecasting methodology, data sources, assumptions, and the past forecasting record of the utility. These parties should have access to transparent information from the utility that allows them to understand and verify the forecasts. Only then can a regulator rule on the validity of the utility's forecasts in setting new rates.

that relate to "specific, clearly identified capital projects and, to the extent appropriate, related to non-capital costs."[74]

2. Treatment of capital costs

a. Five sub-issues

There are five areas of interest about capital projects in the context of MRPs: (1) capital projects allowed in base rates and to be tracked, (2) estimate of the in-service date, (3) projected annual capital costs, (4) ratemaking treatment of forecasting error (hard cap[75], soft cap[76], deferral, cost sharing of overruns with dead bands to account for exogenous factors), and (5) ratemaking treatment of changes in the in-service date, project status and costs. Variances between actual and budgeted costs can occur because of changes in project scope and costs, as well as from plant cancellation or postponement.

b. How utilities can recover capital costs

Over the history of public utility regulation, utilities have recovered their capital costs from customers in various ways. They include:

1. The utility requests cost recovery in the following rate case once a project has been completed.[77]
2. The utility provides forecasts of capital costs and after approval the regulator allows cost recovery on an ongoing basis prior to completion.[78]
3. The regulator pre-approves a project but not its capital costs (i.e., partial regulatory commitment).
4. The regulator allows construction work in progress (CWIP) in rate base.

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74 Minnesota Public Utilities Commission, *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19, Docket No. E,G-999/M-12-587,Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans*, June 17, 2013, 5.

75 A problem with a hard cap is that when a utility reaches it or comes close to it, it may defer capital expenses to the following years, which may delay the completion of a project depriving customers of its benefits.

76 A soft cap gives the utility an opportunity to justify any costs that exceed it. It is more appropriate when the performance metric (e.g., capital expenses for a large project) is difficult to predict and partially outside the control of utility management.

77 The scenario is that all costs are already expended and the project is benefitting customers.

78 One issue is how to allocate cost overruns and underruns between utility shareholders and customers.

5. The regulator applies a used and useful standard (i.e., cost recovery requires completion of a project and its operation that benefits customers).

6. The regulator allows phase-in of capital costs (i.e., longer delay of cost recovery) subsequent to the in-service date.[79]

In recent years, state utility regulators have approved mechanisms (for example, cost recovery riders and surcharge mechanisms) that allow utilities to recover their costs on an "interim" basis outside of a general rate case. These mechanisms attempt to balance (a) the concern of utilities for waiting several years before recovering capital costs and (b) consumer interests in ensuring that recovered costs are just and reasonable or prudent. Regulators can protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case or by approving an incentive mechanism (with explicit rewards and penalties) that motivates a utility to act efficiently in project management.

Ratemaking practices can affect the propensity of a utility to perform efficiently. Cost riders (such as an infrastructure surcharge), especially when they preclude certain costs from undergoing a thorough review by regulators, can compromise a utility's incentive to control those costs, all else being equal.[80] Although regulators may approve a utility's investment plan, the actions of utility management will ultimately determine the final costs and the benefits to customers from the investment.

One option is to allow "interim" recovery of costs for new investments, through a MRP, which will later undergo a prudence review, say, every three years in a general rate case.[81] Utilities will therefore not have to wait several years to receive cost recovery and consumers will get the assurance of a prudence review prior to permanent recovery of costs.

Some state utility regulators have tied cost recovery for investments to utility performance in terms of cost and construction milestones. They have also required a utility to develop a comprehensive strategy, as well as a short-term action plan. Some regulators also conduct a retrospective review to assure customers, for example, that the previous year's or years' costs are consistent with the utility's action plan and prudent construction practices.[82]

Some regulators also cap the amount that the utility can recover through a surcharge. Finally, it is common for utilities to convert cost recovery from the "surcharge" account to base rates in the next general rate case. In the context of an MRP, the regulator can cap the annual capital expenditures that a utility is able to recover. In the next general rate case, the regulator

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[79] The objective is to spread out cost recovery after project operation so as to moderate rate changes over future periods.

[80] Lack of an adequate review causes a utility to worry less about the regulator disallowing recovery some of its costs in rates.

[81] Three years could be the duration of an MRP.

[82] The intent is to assure that the surcharge charge passed through to customers equals only the prudent portion of the costs incurred by the utility.

would determine whether the utility can recover (or refund) any variance of actual expenditures from expenditures that the utility already collected (via the MRP).

Most state utility regulators have approved surcharges, or cost trackers or riders, or MRPs for qualified investments.[83] The usual rationales are that they would:

1. Avoid cash-flow problems and other financial risks for utilities from large investments;

2. Reduce the number of general rate cases;

3. Mitigate short-term high rate increases (i.e., rate shock);

4. Allow regulators to periodically (e.g., annually) review the prudence of a project; and

5. Eliminate any disincentive that a utility would otherwise have to undertake economical investments.

Overall, capital cost surcharges, riders and MRPs can help to avoid drastic one-time rate increases from large projects and mitigate cash flow for utilities by reducing the accumulation of financing costs and regulatory lag. They allow for more timely ("interim") cost recovery during construction outside of a general rate case. On the downside, these mechanisms can result in less-than-satisfactory cost performance by utility management when the regulator exercises inadequate oversight by failing to conduct, for example, a prudence review prior to permanent cost recovery (e.g., rate basing).[84] They also inherently shift risk to utility customers by requiring them to pay for new projects before completion and operation.[85]

3. Challenges with performance targets

Regulators can set either a hard or a soft target for determining the financial effect on a utility from its performance. A hard target results in a penalty when the utility fails to meet the predetermined target, without exceptions, no matter the circumstance. As an example, a utility could recover the actual cost of a capital project, as long as it does not exceed 110 percent of the forecasted cost. One presumption is that costs above this level reflect utility imprudence in managing the project. Setting a target as the threshold for utility prudence, however, can convey a false precision to how regulators are able to interpret different levels of an activity's cost or outcome.

[83] A prominent one for the natural gas industry is new pipes replacing old pipes, especially for safety reasons. A major justification is that investments in replacing aging pipelines (e.g., cast-iron and bare-steel pipes) by themselves do not generate additional revenues for the utility.

[84] Regulatory tools for controlling investment costs include: (a) regulatory monitoring and oversight, (b) mandatory utility reporting of costs, (c) retrospective review, (d) regulatory lag in cost recovery, (e) symmetric incentives, and (f) cost caps (hard or soft).

[85] The risk derives from customers paying for a project before it becomes used and useful. Conceivably, a project could encounter problems that make its completion, and thus its benefits to customers, less imminent.

A dubious practice is to hold a utility to a hard standard or target based, for example, on a peer group of utilities or even on the utility's previous performance. It is presumptuous to conclude that anytime a utility fails to achieve its target, it has acted imprudently. This policy might be unfair to the utility because, say, an "excessive" project cost might come from factors outside its control; or that a relatively low reliability level for a utility might derive from severe weather causing unavoidable outages.[86]

On the other hand, regulators should assume that utilities have some control over the capital cost of a project or their performance in other areas of operation. A perception to the contrary inevitably leads to an open-ended invitation for the utility to pass through all costs to customers with minimal regulatory oversight. Both of these extreme positions seem to make false assumptions that inevitably would lead to inefficient and inequitable outcomes.

A "stretch factor" might be justified if the regulator believes that the utility has a history of being cost-inefficient and has opportunities under better management to improve its efficiency over time. The stretch factor has the benefit of motivating a utility to become more efficient if it hopes to earn its authorized rate of return, which would benefit customers in the long run from lower rates.

Performance evaluation could penalize a utility for not meeting certain threshold levels of performance as measured by selected metrics.[87] Regulators should require utilities to perform well in return for more timely cost recovery and diminished utility risk. They would want to assure the public that the utility does not underperform in any one area, especially when it jeopardizes customer welfare.

[86] Regulators can legitimately ask, however, if a prolonged outage was the utility's fault. Bad outcomes do not necessarily signify an imprudent utility. Penalizing the utility without conducting a retrospective review presumes imprudence when other reasons may explain an unexpectedly bad outcome. Most observers would probably conclude that, besides giving utilities incentives for distorted behavior, this regulatory practice is also unfair.

[87] A poorly structured incentive mechanism can have unintended consequences. Specifically, strategic behavior or gaming by a utility can result in a zero-sum outcome or, worse, distortive utility behavior. The former outcome allocates all the benefits to the utility while producing no real gains to its customers. Distortive utility behavior reduces efficiency as the utility over-allocates its resources to improving the targeted performance area, which decreases the overall performance of the utility. An incentive mechanism can also unfairly harm the utility when (a) its design understates the penalties relative to the rewards or (b) the benchmark is set at a value or range of values that makes it overly easy or difficult for the utility to surpass or even achieve them.

D. Regulators should focus on outcomes

1. Which are most important?

Regulators should focus on certain outcomes in evaluating an MRP, both *ex ante* and *ex post*.[88] The principal ones are:

1. Changes in the efficiency and the cost of the regulatory process;
2. Utility incentives for cost efficiency (e.g., controlling capital costs);
3. Customer benefits in the form of lower, more predictable and moderate changes in rates;
4. Timing and allocation of efficiency gains between the utility and its customers;
5. Ratchets (i.e., resetting new rates relying on past utility costs); and
6. Avoidance of extreme outcomes to strengthen regulatory commitment to an MRP (e.g., via earnings sharing and performance monitoring).

Enhancement of incentives for cost-efficiency can result from no updating of rates between general rate cases[89] and the determination of the allowed revenues for the post-test years beforehand. Incentives for cost control on capital investments depend on (1) regulatory oversight, (2) mandatory reporting of costs and (3) the risk of imprudent allowance. Disincentives for general cost control can come from true-ups that automatically allow utilities to recover unforeseen or under-forecasted costs and to refund customers for over-forecasted costs.

Incentives almost always require some kind of regulatory lag and differences between actual revenues and cost of service revenues. The challenge for regulators is to create a balance between effective incentives and prevention of politically unacceptable high profitability levels or the threat of utility financial suppression jeopardizing capital attraction and other utility activities.

Ratchets dull incentives for cost efficiency.[90] With a three-year plan, for example, a dollar of cost savings in year one is worth more to the utility than a cost savings of one dollar in year two, since the utility retains the cost savings for a longer period until the next rate reset

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[88] *Ex ante* evaluation helps to determine whether the regulator should approve an MRP. *Ex post* evaluation monitors the outcomes to determine whether the plan performed as expected and how the regulator can improve the plan to achieve better outcomes in the future.

[89] This can occur with a rate freeze, a stay-out provision or the absence of an earnings sharing component.

[90] Ratchets involve the regulator's adjustment of future forecasts based on past forecasting errors. The regulator observes the utility's actual costs *ex post* to reset a future price. The "ratchet effect" reflects dynamic strategic behavior that analysts and practitioners often ignore in predicting the actions of public utilities and their regulators.

occurs. The regulator would presumably look at a utility's costs and deduct from them the amount that the utility over-forecasted in a prior period. Since regulation is a repeated game, regulators can learn about a utility's true cost attributes as they observe its behavior and performance over time. A utility would tend to inflate costs during the test year, so that it can better justify higher costs in future years. This assumes that the utility expects future earnings to depend on the calculation of test-year costs and revenues. The lower the test-year costs are, for example, the lower future rates will be and, other things held constant, a utility's earnings.

2. Expected outcomes from MRPs

What should regulators expect from MRPs in terms of utility performance? The answer depends on the combination of the core features and add-ons that we previously discussed, and the execution of an MRP. One critical factor is the calculation of revenues during the post-test year period. The calculation can represent forecasts of a utility's costs or indices based on some general or industry-specific price index. Another crucial element relates to which capital costs get included in an MRP.

One positive feature of MRPs, relative to traditional ratemaking, is that they return sooner in time to customers the benefits of improved utility operating efficiency. Lengthening regulatory lag or otherwise strengthening incentives postpones the ultimate objective of passing on benefits to customers. This tradeoff is also inevitable in any incentive plan where the regulator attempts to balance the strength of an incentive and customers benefitting from improved utility performance.[91]

MRPs have a distinct advantage over traditional ratemaking in alleviating the likelihood of the utility's encountering financial difficulties. For example, MRPs provide for quicker and more certainty of utility recovery of capital costs.

Yet, the ultimate question for regulators comes down to how customers would benefit. Benefits to customers largely depend on whether the utility becomes more cost-efficient and that customers receive some of those benefits through lower rates. A financially stronger utility also benefits customers in the long run. For example, facilitating utility recovery of project costs may reduce the cost of capital for new investments and the hesitance of a utility to invest in projects that can benefit customers.[92]

Fewer general rate cases can benefit both utilities and regulators. For customers with a longer duration between general rate cases, utilities should have more incentive to control their costs. Fewer rate cases also drive down the regulatory costs for utilities and other stakeholders.

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[91] A tradeoff exists between providing a strong incentive for the utility to manage its costs and ensuring an adequate distribution of the gains to customers. Any incentive mechanism would need to balance these two objectives, implicitly setting a value for s that reflects the relative weights assigned by a regulator to creating "high-powered" incentives and assuring sufficient benefits to customers.

[92] Otherwise, a utility may not undertake socially desirable capital projects in the absence of an MRP. Whether this premise is true requires regulators to conduct a case-by-case review.

MRPs can increase the predictability of rates to customers. Still, the presence of riders and surcharges may prevent customers from knowing with complete certainty what rates they will pay over, say, the next three to five years.

To the extent that the test-year concept under traditional ratemaking is incapable of setting rates for a multi-year period, some alternative way for utilities to recover costs becomes necessary. The term "incapable" here refers to the inability of test-year costs and revenues to reasonably reflect conditions during the effective periods of new rates. Piecemeal approaches such as cost trackers for individual functions (e.g., investments in new projects) and revenue trackers only partially address some of these problems. MRPs could more effectively and comprehensively overcome them, especially in a dynamic environment, with a "static" test-year approach featured under traditional ratemaking.

VI. Major Concerns with MRPs

A. Challenges in evaluating utility forecasts

Regulators may find it difficult enough to check the accuracy of baseline costs and revenues under a future test year.[93] Checking the accuracy of forecasts three or more years out into the future, which some MRPs require, poses even more challenges.

1. Information asymmetry

Forecasts, whether multiyear or single-year, have intrinsic problems. One is information asymmetry in which regulators observe only a utility's performance, not the separate effect of management effort on cost, service quality and other outcomes affecting customers' well-being.[94]

It becomes difficult for regulators to know whether the utility's forecasts are reasonable and objective.[95] Utilities should have the burden to support their forecasts.[96] An example of information asymmetry is what economists call the "market for lemons." In that market, the party with the better information will leverage its favorable position to its advantage. A seminal economics article says that in markets plagued by information asymmetry, the market participant holding an information advantage will likely dominate the outcome at the expense of others.[97] For multiyear forecasts, the implication is that any outcome would be favorable to the utility and harmful to its customers.[98] This possibility raises a serious concern that may partly explain why most state utility regulators have withheld their support for MRPs and even for future test years.

Supporters of MRPs (largely utilities and Wall Street investment houses) seem to understate the seriousness of information asymmetry. Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between

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[93] *Supra* note 21.

[94] *Supra* note 62.

[95] Consumer groups and others may argue that forecasts of capital investments are not "known and measurable."

[96] Although the utility may have the burden to demonstrate the reasonableness of its forecasts, any proposed adjustments by other parties would require an evaluation showing the forecasts' inaccuracies. The utility has a big advantage over other parties in knowing its prudent costs. It is difficult for a regulator's staff and interveners to either (a) show that the utility's costs are excessive or (b) produce their own forecasts that reflect efficient utility management. For the regulator, it comes down to a judgment call in determining the appropriate cost under an MRP.

[97] George A. Akerlof, "The Market for 'Lemons': Quality Uncertainty and the Market Mechanism," *The Quarterly Journal of Economics*, Vol. 84, No. 3 (August 1970): 488-500.

[98] As a rule, regulators should apply caution in interpreting information that is asymmetrical, insufficient, and uncertain.

forecasted costs and utility-management competence.[99] When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.

2. Biased forecasts

Knowing whether utility forecasts under an MRP are objective and unbiased is essential for protecting customers from unreasonable rates. Utilities would have an incentive to overstate their costs and understate revenues.[100] They may also have subpar forecasting capability and some costs or revenue items may just be inherently difficult to forecast.

One approach to eliminating forecasting bias comes from the United Kingdom. The country's distribution utilities can choose from various plans that have different combinations of revenue requirements and earnings-sharing arrangements. A utility can opt for a plan that has a high revenue requirement for which it retains a low share of the cost savings; or a plan that has a lower revenue requirement for which the utility keeps a higher share of the cost savings. The benefit of this approach is that the utility would select the option that reveals its own unbiased estimate of future costs, thereby mitigating if not avoiding the over-forecasting of costs.[101]

Checking for the accuracy of past forecasts is essential. Since regulation is a repeated game, regulators can learn about the credibility of past utility forecasts and a utility's attributes, as regulators observes the utility's actions and performance over time.[102]

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[99] Asymmetry comes from the absence of the regulator's knowledge about the utility's cost opportunities and managerial effort. Because of this reality, the utility has a strategic advantage over the regulator and non-utility stakeholders.

[100] A utility would be more inclined to overstate costs than to understate costs. The utility expects the regulator to lower its cost forecasts, so it would tend to initially file inflated costs. There is little payback for a utility that hedges on the low side. The likelihood of the utility's actual costs being higher would increase, thus jeopardizing its rate of return and penalizing its shareholders.

[101] *Supra* note 40.

[102] Regulators can require utilities to measure the accuracy of their past forecasts. They can then compare the actual costs and revenues with what the utility forecasted during the previous rate cases. If a utility applied a model to derive these forecasts, it should identify the different causes of forecast errors. To what extent were errors the result of (a) wrong assumptions for specific predictors or (b) model estimation errors? The legitimacy of applying the same model to predict the future partially depends on the model's historical forecasting performance.

A regulator can also view whether forecast errors occurred predominantly in one direction: Were cost forecasts consistently high or sales forecasts consistently low? A regulator can also rely on past forecasting errors as a guide to set a tolerance level for an MRP. If past forecasts exhibited large errors, a regulator might want to consider alternatives to using an MRP for setting future rates.

3. Generic issues with forecasts

Reliance on multiyear forecasts raises the legitimate question: Are forecasts sufficiently accurate for setting rates? For sales and large cost components, the forecasting error in percentage terms could be small and still have a non-trivial effect on the utility's earnings. As a general matter, forecasters tend to overstate the accuracy of their predictions even when based on sound techniques.[103] When adding the "bias" element intrinsic to a utility's forecasts, one can easily imagine why forecasts might fail to adequately reflect the utility's cost, operating and other conditions over the test year and beyond.

For many items forecasts are not robust, in that they are highly sensitive to future scenarios of the world. Electricity sales for next year, for example, depend on economic conditions, price, weather, and customer behavior. Arguments over the numerical value for each predictor—and how it affects electricity sales—would be contentious and time consuming in a rate case. The regulator has the tricky task of selecting what it considers the most accurate single-point forecast. Basing a decision solely on a single-point or "best guess" forecast is risky. Usually in different contexts it is valid only when (1) the decision maker places a high degree of confidence in a single-point forecast, and (2) the consequences of an incorrect forecast are small.

To elaborate, forecasters typically express their predictions as a range of values within which an event (e.g., future sales) has a high probability of occurring. The uncertainty of predicting costs and sales gives theoretical support for regulators to look at a range of possible future scenarios, rather than focusing only on the most probable future state (i.e., the "best guess" forecast). Regulators should therefore not base their decisions on a single-point forecast, even if that forecast is more defensible than all the other forecasts. Yet in setting rates, whether from a future test year or an MRP, regulators have no choice but to select a single-point forecast, knowing with almost absolute certainty that it will contain a margin of error. In some instances, forecasts are no more than an educated guess, which makes them especially suspect for setting rates. The policy question ultimately reduces to: Are forecasts sufficiently accurate for use in setting rates to avoid an "extreme" rate of return, especially on the high side? If regulators have any doubt, they should seriously consider an earnings-sharing add-on to an MRP.

4. Questions with forecasts from budget data

Utilities often use budget data to forecast costs in a future test year or an MRP filing. Several questions arise as to their validity:

1. Does the utility use a "best practice" budgeting process?

2. Does the utility adequately document its budget?

3. How does budgeting link to the utility's long-range planning?

4. Does the utility provide supporting analyses?

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[103] Nate Silver, *The Signal and the Noise: Why So Many Predictions Fail—But Some Don't* (New York: The Penguin Press, 2012).

5. Do budgets satisfy the "matching principle"?

6. Are budgets forecasts or, instead, goals that do not represent "best guess" cost estimates?

7. What assumptions does the utility make?

8. What are the cost drivers?

Often, a utility's actual spending may not coincide with its budgets. Should a utility then develop separate forecasts for their future costs? Utilities will often forecast their O&M costs based on budget data. Some analysts consider budgets "wish lists" and not best-guess cost estimates for specific utility functions. Budgets may not always align with sales or other costs, violating the "matching principle" that is essential for setting rates.[104] For example, if a utility develops a budget for each function separately and not jointly with other budgets, inconsistency among different budget items can occur.

B. Dubious incentives for cost efficiency

Three reasons explain why a utility's costs may inflate its costs. One reason is self-fulfilling forecasts to avoid a "ratchet effect." What we mean here is that a utility may intentionally increase its costs to make its forecasts seem more accurate. Another possibility is the utility imputing in an MRP forecasted cost increases that are yet to be determined. A utility, for example, might have a weaker incentive to negotiate wage increases below the amount already included in rates. A third, and probably most important, reason lies with information asymmetry, in which the regulator would find it difficult to identify imprudent costs in a utility's rate filing. As such, the threat of disallowed costs lessens, thereby removing an important regulatory tool to control a utility's costs. Overall, an MRP might score poorly in achieving cost efficiency.

On the other hand, regulators can strengthen a utility's incentives to control costs by allowing recovery of cost changes beyond the effective rate year based on indexes that do not track an individual utility's actual costs.[105] By removing this cost-plus feature of traditional ratemaking, utilities would earn higher profits from reducing their costs.

Overall, the strength of utility incentives depends on the MRP's structure. An MRP provides utilities with differing performance incentives, depending on whether allowed rate adjustments derive from (1) forecasted costs for a utility or (2) indexes that are exogenous to an individual utility's actual costs. The latter approach provides a utility with stronger performance incentives. Nearly all of the real-world plans have "stay out" provisions that provide an additional utility incentive for cost efficiency, as well as reduce the frequency of rate cases.

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[104] Two core features of a test year are (a) that the calculations of revenues, expenses, and rate base occur over the same time period and (b) the presence of consistency among the different costs and sales elements. The latter requires, for example, that the O&M forecasts are compatible with the sales forecasts and that operating costs account for new facilities added to the rate base.

[105] *See*, for example, *supra* note 5.

C. The problem of premature utility recovery of capital costs

Under traditional ratemaking, the utility would have to file a new rate case before recovering any of the costs for a new capital project completed outside the test year. Exceptions are when the utility has a special surcharge or tracker that allows it to recover costs in the absence of a general rate case.[106]

MRPs pose a special problem for regulators in how they should address unexpected delays, cost overruns, and even cancellations of new capital projects. If the utility's forecast turns out to be overly optimistic, customers may end up paying for new projects prior to in-service status. As an example, a regulator may approve an MRP that ends in 2019 that included costs for a new electric transmission line expected to be in service by June of 2019. Assume that the line encounters delays that set a revised expected completion date of early 2020. Customers are then paying for the line without receiving any benefits from it. This prepayment might not pose a problem in states that allow, for example, CWIP in rate base, but for other states it would.

MRPs, in addition to infrastructure surcharges, can erode utility incentives for capital-cost management if the regulator less scrutinizes those costs. Such an outcome is conceivable when a utility recovers those capital costs from customers before regulators review them. MRPs, in addition to infrastructure surcharges, also have the problem of requiring customers to pay for capital projects that are not yet used and useful, which violates the beneficiary-pays principle because no benefits can flow from a facility before its construction is complete. Overall, utility shareholders seem to benefit at the hands of customers. Yet, customers may in the end benefit when a utility would only undertake investments for which customers prepay.

[106] A regulator may consider appropriate a so-called negative tracker or rider in the event customers are paying for a new plant that unexpectedly encountered delays in completion and thus not providing them with any benefits. The rider, which would involve the utility crediting customers, could continue until the time that the plant actually goes into service.

VII. When Can MRPs Be in the Public Interest?

A. Three steps for evaluating MRPs

A rational process for evaluating MRP involves regulators ordering and interpreting the information they have available to best advance the public interest. This approach requires that regulators: (1) define the public interest in terms of the objectives they ascribe to ratemaking, (2) understand the effect of alternative ratemaking proposals on advancing and impeding the different objectives, and (3) process all the information logically and systematically.

An idealized vision of regulation is as a social institution that makes reasoned (i.e., rational and systematic) decisions based on expert and objective assessment of all the relevant information, and is driven to advancing the public interest. This inevitably requires regulators to exercise judgment by processing the information for decision making.

What this all means is that in evaluating MRPs, regulators need to fulfill their duty to serve the public interest by being well-informed and logical in interpreting the information they have available. Even if an MRP bolsters the financial health of a utility, it may still fail to serve the public good if customers become worse off.

B. Different perceptions of the public interest

What constitutes the public interest is subjective but regulators over time have associated it with just and reasonable rates. A different perception of the public interest is the composite indicator of the public well-being that "adds up" the individual effects of an action on stakeholders and other societal interests.[107] A third perception relates the public interest to the stakeholders' collective consent to a regulatory action. The idea is that the aggregate interest of society overrides the well-being of special interest groups.

While few would dispute that advancing the public interest is an admirable goal, little consensus exists on how to define and achieve it. Many state utility regulators associate the public interest with meeting minimum fairness requirements; for example, the fair treatment of utility investors and protection of core customers. Even though fairness is a subjective term, regulators must establish bounds and rules to distinguish between fair and unfair actions.

A narrow definition of "the public interest," more in line with traditional regulation, is the long-term interests of utility customers.[108] After all, the original rationale for public utility

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[107] This definition, which state utility regulators have increasingly ascribed to over the past several years, would include outcomes related to energy efficiency, clean air, and affordability.

[108] Economists refer to consumer welfare in terms of what they call "consumer surplus," which measures the value customers received from a product or service minus the monetary and nonmonetary (e.g., search costs) outlays. With an MRP, for example, consumer surplus, conceivably, could increase because of (a) reduced prices, (b) the availability of additional services (e.g., value-added services), and (c) an increase in the quality of service.

Technically, consumer surplus is the area under the demand curve and above the price. When customers pay a higher utility rate, their consumer surplus decreases by the sum of (a) the loss in net regulation was to protect customers from the monopoly power of utilities. The "long-term" aspect means that holding rates down in a pending rate case may jeopardize the ability of the utility to fund new investments benefiting customers.

Long-term customer welfare, arguably, is one of the least represented interests in the regulatory and political arena. Utilities look out for their financial interests,[109] and consumer advocates tend to take a short-term view. An apparent gap in adequate representation for the long-term interests of customers demands regulators to fill that void, notwithstanding the intense pressure they face to appease individual stakeholders with the most clout.

In sum, these are all guideposts for regulators to consider in evaluating an MRP. As this paper stresses, regulators should look at the totality of an MRP in what effects it will have on the different stakeholders, especially utility customers from a long-term perspective.

C. Desirable outcomes taking into account the economics and politics

It is not clear whether MRPs are in the public interest. The term "social welfare" or "the public interest" is multidimensional in nature. A regulatory review of alternative rate mechanisms such as MRPs therefore requires consideration of fairness, economic, utility, financial health, and other outcomes. All rate mechanisms have mixed outcomes from the perspective of the public interest, and MRPs are no different. Regulators must use judgment to assess their overall effect, combined with the best information available to them. Much depends on the details and implementation.

From a theoretical perspective, MRPs have especially attractive features in a dynamic world. They should have three essential features to enhance customer benefits. One is that utilities have good incentives for cost efficiency. The second is that utilities are held accountable for their performance.[110] A third, which is more debatable, is that for political purposes an MRP should have a safety net or set boundaries for outcomes. Earnings sharing is one prime example.[111] Otherwise, opposition from stakeholders or from regulators themselves would make the duration of an MRP fragile. This political reality has the downside of diluting the potential

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benefits from less consumption and (b) the additional payment for consuming at the actual level compared with what they would have paid at the same consumption level under a lower rate. When the higher rate is above the utility's prudent costs, it results in what economists call a "deadweight loss" (i.e., aggregate economic-welfare loss).

[109] Utility management could have different interest than their shareholders. Management might place greater emphasis, for example, on immediate or short-term financial performance whereas shareholders might have a longer-term horizon (e.g., the average rate of return over a ten-year period).

[110] Without accountability, a utility operates in a "moral hazard" environment in which it becomes indifferent to actions that would benefit customers. An unwillingness to expend additional effort to reduce O&M costs and to suffer no consequences from this inaction is an example.

[111] Inherent forecasting problems, which we previously discussed, is a rationale for earnings sharing. It can temper the extreme effects that could result from large forecasting errors (e.g., exorbitantly high or excessively low utility profits), jeopardizing the regulatory commitment to MRP.

total benefits (e.g., robust incentives for utility cost efficiency) that an MRP can offer.[112] This tradeoff is inevitable and should enter the regulator's decision-making process for determining the desirability of an MRP. A challenge, as previously discussed, is to avoid a utility's earnings from being extreme while also providing the utility with good incentives to be cost-efficient.[113]

D. Cardinal principles for cost recovery

One additional question relates to how well MRPs align with the major principles for cost recovery applied by state utility regulators over the years. Namely, cost recovery should:[114]

1. Reflect, in a reasonable way, the prudent costs of a utility, either incurred in the past or projected for the future;

2. Avoid rate shock that can especially burden low-income households who would find it difficult to afford utility services and other necessities;

3. Avoid jeopardizing a prudent utility's financial health; a regulator may want, in special circumstances, to mitigate cash flow problems by allowing a utility quicker cost recovery; and

4. Avoid placing onerous burdens on either utility customers or shareholders; this balance may require a tradeoff between immediate cost recovery (or before-project-completion) and delay of cost recovery until after the next rate case.[115]

Where a utility has much discretion over costs, regulation should consider (1) providing the utility with either a robust incentive to control them, (2) establishing performance standards, or (b) monitoring and conducting prudence reviews.[116] Allowing for "automatic" cost recovery

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[112] The upside for customers is that they will reap the benefits of unexpected efficiency gains prior to the next general rate case.

[113] An earnings sharing structure requires both the utility and customers to share both the risks and rewards.

[114] How regulators frame cost recovery is critical in examining (a) what costs they should allow utilities to recover, (b) how utilities should recover them, and (c) when they should recover them. Utilities sometimes convey the misleading impression that they have a right to recover any costs they incurred, even before the regulator has assessed their reasonableness. Their position seems to be that "we expend money to satisfy mandates or serve our customers, so regulators should allow us recovery of this money in rates even with little scrutiny." It presumes that regulators should trust that utilities will always act in the public interest. Good regulation would question the prudence and legitimacy of any costs; it owes that much to utility customers. As in other situations, regulators should not expect utility interests to coexist with the public interest, which after all is the rationale for public utility regulation.

[115] The balancing act of regulation, long practiced by state utility regulators, requires the setting of rates to not excessively burden utility customers while allowing a prudent utility to sustain financial health.

[116] One criticism of the prudence standard for evaluating a utility's performance is that a utility can satisfy it without performing at an above-average level. It establishes a threshold of minimum acceptable performance; it does not distinguish acceptable performance from exceptional performance. A

or recovery with minimal scrutiny would weaken utility accountability to manage costs, thereby shifting excessive risk to utility customers. Regulators would want to avoid such a practice under an MRP or other ratemaking mechanisms.

E. The benefit of merging different ratemaking mechanisms

Consolidation of different rate mechanisms is a potential benefit of MRPs. It can simplify and make more efficient the regulatory process. We have seen a proliferation of new ratemaking methods that try to advance certain objectives (e.g., energy efficiency) and facilitate recovery of costs for utilities (e.g., cost trackers, riders and infrastructure surcharges). These are largely piecemeal approaches that focus on some narrow area of a utility's operation.

An MRP can substitute for some cost trackers. As a comprehensive ratemaking mechanism, an MRP can eliminate the need for different cost trackers.[117] Cost trackers can diminish the positive aspects of regulatory lag and retrospective reviews.[118] They can also create distorted incentives because of dissimilar cost-recovery methods across a utility's functional areas.[119] With non-uniform treatment of different costs, for example, the utility might find it profitable *not* to pursue cost-minimizing objectives.[120] The rationale for cost trackers is to prevent a utility from suffering serious financial problems between rate cases. The question is whether a rate-of-return-driven mechanism such as an MRP or a formula rate plan has the potential to better achieve this objective than myriad cost trackers.

In sum, MRPs are a comprehensive approach for setting base rates that varies in major ways from traditional ratemaking.[121] MRP offers a holistic approach to setting rates that can

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commission in effect grades and evaluates utility performance dichotomously: The utility's behavior is either acceptable or unacceptable; there are no intermediary levels of utility-management competence.

[117] The reader may ask whether revenue trackers such as revenue decoupling could also not be eliminated. One answer is that it may be preferred to continue with revenue decoupling to remove the disincentive that a utility may have toward energy efficiency, even with an MRP that has earnings sharing.

[118] An important incentive for cost efficiency by regulated utilities is the threat of cost disallowance from a retrospective review. To the extent that an MRP reduces the effectiveness of these reviews, incentives for cost management further erodes. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over its costs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to control costs. Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty, making the utility more diligent and careful in its planning and operations, for instance.

[119] *Supra* note 22.

[120] An MRP applying indexes for attrition adjustments also has more robust incentives for cost control than trackers that follow changes in a utility's actual or report costs.

[121] We have observed over time more diversity and dissimilarity of ratemaking methods across states. One explanation may be that some states have expanded the objectives they assign to regulation while others have stuck to core objectives, which include financially healthy utilities, high service quality and reasonable rates. Another explanation is the differences in relative strengths that various stakeholders

obviate the need for many of the trackers that currently exist. One benefit is that a regulator can review different rates on more of a level playing field and mitigate the problems with one-issue ratemaking.

(e.g., utilities, consumer groups, renewable energy and energy efficiency advocates) have across the states.

VIII. Summary and Final Thoughts

The basic question posed in this paper is how MRPs rank with other ratemaking mechanisms in advancing the public interest. In some U.S. applications, MRPs are more of an adaptation to traditional ratemaking (e.g., applying the future test-year concept over more than one year) in setting base rates. The version of MRPs widely used in other countries – price cap regulation – represents more of a radical departure from traditional U.S. ratemaking, with good qualities that merit serious consideration by U.S. utility regulators. But other versions tainted by politics and dominance by a single interest group contain elements that make them suspect for serving the public interest.

This paper discusses how MRPs in theory can advance the public interest, but the proof of their social desirability hinges on real-world constraints (e.g., political, relative stakeholder dominance) and their implementation. MRPs therefore have attractive features that can benefit customers and the public interest. But, as it is true with other ratemaking paradigms, the "devils are in the details". The real test is whether MRPs improve the performance of utilities so as to benefit their customers in the long run.

Regulators need to balance strong utility incentives to control costs and healthy finances for a prudent utility. This may require adjusting rates between general rate cases to account for changing costs and sales. Even when traditional ratemaking uses a future test year, which reduces the time lag between changes in rates and costs relative to an historical test year, it fails to update base rates for the attrition that may occur after the rate effective year. Utilities have argued that attrition reduces their ability to earn the authorized rate of return. Riders, trackers and surcharges can allow for rate adjustments between general rate cases, but they have their own special problems that MRPs can help to mitigate.

Because MRPs can have uncertain and unexpected outcomes, regulators may want to initially consider them as a pilot program. As such, post-evaluation becomes imperative, in deciding whether to continue with MRP permanently. It can also lead to tinkering with the structure of an MRP to improve future utility performance and enhance customer benefits.

Why MRPs are not more popular for U.S. energy utilities is somewhat puzzling, given their attractive features – although perhaps not. Possible explanations include inertia, perceived/real problems with MRPs (e.g., forecasts of three years or so into the future), opposition by non-utility stakeholders, utilities seeing little gains, and recent regulatory and public policy stressing environmental and energy efficiency goals.[122] MRPs have been much more common in the telecom industry than in the energy utility industries. One explanation is that the energy utilities have had fewer opportunities to offer discretionary services.[123] In the

[122] Price cap regulation, for example, encourages utilities to increase their sales in order to recover their fixed costs, which is at odds with the policy goals of energy efficiency and clean air.

[123] *See*, for example, David E.M. Sappington and Dennis L.Weisman, "The Disparate Adoption of Price Cap Regulation in the U.S.Telecommunications and Electricity Sectors," *Journal of Regulatory Economics*, Vol. 49 (2016): 250-64. Another explanation may be the nature of costs in the telecom industry compared to the electric industry. In the electric industry, costs may be increasing, are lumpier, and more capital intensive. From the utility perspective, other available alternatives like CWIP and cost-

implicit agreement between the regulators and the telecom companies, regulators imposed little regulatory oversight of discretionary services in return for protecting customers of local telephone service via price caps. The fact that price caps are uncommon in the energy utility industry also suggests that economic efficiency has not held a high standing in those industries.[124]

Utilities to date have made less-than-compelling arguments in support of MRPs.[125] Their main argument is that MRPs would improve the regulatory process and their financial condition (e.g., from less regulatory lag).[126] They seem to have fallen short in convincing regulators how their customers would benefit. Utilities have recently emphasized the need for an MRP to facilitate recovery of capital costs between general rate cases; specifically, to allow utilities to recover their capital costs more promptly and with more certainty. One circumstance justifying an MRP is when a utility is embarking on several large capital projects with the projects coming into service in successive years. An MRP could allow a utility to include in rate base projects completed in each year of the covered period, so that it could avoid filing back-to-back traditional general rate cases. Regulators guaranteeing a certain revenue stream, as some utilities have argued, is critical for efficient planning. While these desirable outcomes may well transpire, the downside is the lack of opportunity that a regulator may have to review the prudence of costs that utilities want to recover from customers.

Perhaps the biggest challenge for regulators lies with knowing whether under a proposed MRP the utility's forecasts over a three- or five-year period are reasonably accurate. Poor forecasts can lead to extreme utility earnings, either on the high side or low side; but information asymmetry would tend to favor utilities by allowing them to receive high earnings. These plans also require more time expended by a regulator's staff and other parties to evaluate them, in addition to increasing the complexity of rate cases.

In the end, regulators will need to address three broad questions in evaluating MRPs.

1. Given a regulator's objectives of ratemaking and their relative importance, how do MRPs stack up with alternative ratemaking methods, including traditional ratemaking?

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recovery riders for capital projects may act as suitable substitutes for MRPs. Another possible explanation for the lack of popularity for MRPs that rely heavily on forecasts is the difficulty of showing the benefits to customers and suspicion by regulators that the forecasts are biased and difficult to review.

[124] Another reason may be that regulators feared that price caps would jeopardize service reliability because of the strong incentive to control costs.

[125] In other countries, the initiator of MRPs has been the utility regulator or other policymakers.

[126] One possible exception to this is when a utility spends on large capital projects whose commitment by the utility could cause financial difficulties with long delays in cost recovery.

2. What ratemaking mechanism or group of mechanisms would be most effective in achieving those objectives? "Effective" can mean attaining some outcome at least cost or with minimal inefficiencies.

3. Perhaps most important, what ratemaking mechanism would be both fair to the utility and most beneficial to customers? How can an MRP produce a non-zero-sum outcome, i.e., result in benefits to both the utility and its customers? The key to advancing the public interest is to make someone better off without making anyone worse off. If MRPs can accomplish that, they should become part of a utility regulator's rate setting portfolio.

In conclusion, utility regulators may want to take the initiative in advancing MRPs oriented toward the public interest, rather than just the narrow interests of individual stakeholders. This paper suggests that their efforts can produce dividends for utility customers and society at large.

Appendix A: General Questions on MRPs

1. Should rates and revenues be determined beforehand or should a formula determine post-test year rates?
2. What are the benefits of regularized regulatory lag (i.e., known and fixed periods between general rate cases)?
3. What should be main rationales for MRPs?
4. What can go wrong with MRPs from the perspective of utility customers?
   Bad forecasts and poor incentives are two examples that come to mind. A worst case scenario is when a utility earn excessive returns while performing below par; or the opposite where a high performing utility has deficient earnings.
5. Why are MRPs not more common in the U.S.?
6. How are MRPs theoretically superior to traditional rate-of-return ratemaking?
7. How can MRPs improve the performance of a utility?
8. How do the incentives under an MRP affect a utility's performance?
   Ironically, while an MRP reduces regulatory lag, it can increase a utility's incentive for cost efficiency.
9. Are MRPs the most effective and efficient approach to addressing the problems underlying traditional ratemaking?
10. Which out-of-test-year costs should a utility forecast based on its costs, and which should be subject to an index or formula?
11. How do MRPs promote core and other regulatory objectives?
12. What essential features should an MRP have in promoting the public interest?
13. To what extent should actual utility earnings remain unadjusted between general rate cases?
    Some analysts would argue that MRPs without earnings sharing would fail to produce an optimal outcome given asymmetric information and uncertainty over future costs.
14. How would MRPs affect energy efficiency and distributed energy resources?
15. What are the main arguments against MRPs?
16. What outcomes can we expect from MRPs?
17. How can MRPs benefit customers?
18. How can MRPs benefit a utility?
19. What are the major features that regulators should review to determine whether an MRP advances the public interest?

Appendix B: Questions for Regulators to Ask about MRPs

1. What special conditions warrant rate or revenue adjustments outside of a general rate case? In other words, what makes a general rate case unique?
2. Should a proposal for an MRP coincide with a general rate case or with major capital expenditures?
3. In addition to an MRP, what other mechanisms exist to allow a utility to adjust rates between rate cases? Examples are cost trackers, capital surcharges and revenue trackers.
4. What evidence should a utility present to show the justification for an MRP?
5. From the perspective of the public good, how should a regulator weigh the benefits of an MRP relative to its costs? Under what conditions would the benefits dominate the costs to justify an MRP?
6. How would an MRP affect the utility's incentive to improve its cost performance?
7. How can the regulator assure customers that they are paying only for prudent and efficient costs, or for costs that benefit customers? This is essential for determining whether rates are just and reasonable. Specifically, how can the cost-review process assure that the utility is unable to recover excess costs from customers?
8. How would an MRP affect the utility's non cost-related performance? Should an MRP include standards for utility performance?
9. Should costs for capital projects be recovered during an MRP even if the in-service dates are beyond the last year of the plan?
10. If the concept of an MRP is deemed appealing, how can a regulator structure it to mitigate potential problems that would cause harm to customers?
11. How long should an MRP operate (i.e., its duration) before the utility has to file a general rate case? This question relates to: What are the costs and benefits of shortening or lengthening the duration of an MRP?
12. What criteria should regulators use, if any, to determine the range of rate of return within which no rate adjustment would occur? Should regulators, for example, even adjust the utility's actual rate of return between rate cases?
13. How should regulators decide between general rate cases on the sharing of excessive or deficient rate of return between shareholders and customers?
14. What should regulators determine as the utility's post-rate adjustment rate of return (i.e., the targeted rate of return)? Options include the lower and higher bounds of a specified dead band region, the authorized rate of return established at the last general rate case, and some portion of the difference between the pre-adjusted actual rate of return and the boundary points.
15. What have been the experiences of MRPs in different jurisdictions? As an example, Xcel's Colorado multiyear rate plan was approved in a 2011 electric rate case as a result of an uncontested settlement agreement among all of the parties in that rate case. The plan ended when new legislation required the Commission to implement other ratemaking mechanisms.

The MRP contained the following components:
(a) new, higher base revenue amounts (i.e. rate increases) are implemented in January 1 during the term of the MRP;
(b) the overall dollar amount of the base rate increases are set for the term of the plan; there is, however, an annual reconciliation between the amounts authorized and actually recovered in base due to variations between actual and forecasted sales; additional adjustments are allowed for variations of more than two percent;
(c) the Commission handles annual adjustments to base rates through letter (or compliance-like) filings; and,
(d) additional increases in base rates are prohibited during the term of the plan.

As part of the rate case settlement, and for the duration of the MRP, Xcel agreed to forgo recovery of CWIP; a reduced rate of return; and no changes to the allocation and design of its base rates, a sharing mechanism in which customers share in the Company's earnings that are in excess of the Commission's authorized rate of return on equity. In 2013 and 2014, the utility refunded $8.4 million and $66.5 million, respectively, to customers. In discussions with the author, certain staff members of the Colorado Public Utilities Commission indicated their lack of enthusiasm for MRPs mainly because of the difficulty in verifying the forecasted costs.