Multi-Year Rate Plans

Core Elements and Case Studies

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AUTHORS

Melissa Whited
Cheryl Roberto

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. CORE ELEMENTS OF MULTI-YEAR RATE PLANS

Multi-year rate plans (MRPs) are widely used around the world and have been in place for many decades in a variety of industries. MRPs are also known as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan. Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years).

Jurisdictions typically implement MRPs to achieve some or all of the following goals:

- Provide the utility with cost containment incentives
- Encourage innovation by allowing the utility to manage business decisions with greater flexibility.
- Reduce regulatory costs and burdens.
- Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.

Modern MRPs generally cap allowed revenues, rather than prices, in order to reduce the utility's throughput incentive and encourage the utility to focus on cost reductions rather than increasing revenues. The utility is typically allowed to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan.[1]

Under an MRP's rate case moratorium, the utility must refrain from filing a new rate case for the duration of the plan. This moratorium generally lasts three to eight years and ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge. This shifts the risk associated with poor utility cost management to utility shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.

During the rate plan, revenues may either be held at a fixed level or be adjusted according to a pre-defined formula called an "attrition relief mechanism" or "ARM." An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. Importantly, the formula does not track the utility's *specific* costs. As explained in the Edison Electric Institute's survey of alternative

[1] However, as discussed in sections 3.1 and 4.2, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

regulation mechanisms, "[t]he rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth."[2]

In this manner, an MRP is similar to traditional cost of service regulation with a revenue decoupling mechanism, since the utility's costs do not necessarily equal revenues between rate cases, but the utility is still allowed to recover its allowed revenues (regardless of changes in sales). The primary differences from cost of service regulation with decoupling are:

- Allowed revenues can be increased annually through an ARM instead of frozen, and
- The utility agrees to not file another rate case for a set number of years (i.e., a rate case moratorium).

Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case.

To summarize, there are four key design elements that are critical to MRPs:

1) **Revenue Cap:** Revenues are capped at certain pre-determined levels.
2) **Attrition Relief Mechanism (ARM):** The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs that the utility has no control over.
3) **Rate Case Moratorium:** A "stay-out" provision limits the ability for rates to be reset during the plan.
4) **Incentive to Improve Efficiency:** Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains.[3]

While MRPs can provide strong cost containment incentives and reduce regulatory burden, they also present two key risks. First, the utility's costs may deviate substantially from its allowed revenues during the rate plan. Second, the revenue adjustments provided by an index may not provide adequate revenue for new and unusual investments.

To address the first concern, regulators have often implemented consumer protection measures, such as earnings sharing mechanisms, to ensure that the utility does not over-earn excessively. For example, the utility may be allowed to earn 200 basis points above its allowed ROE, but beyond that it must share some of the extra earnings with customers.

[2] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

[3] Conversely, ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.

To address the second concern, certain costs may be pulled out of the MRP and treated separately. For example, Massachusetts removed Eversource Energy's grid modernization investments from the MRP and is allowing recovery of those costs through a separate "Grid Modernization Factor."

MULTI-YEAR RATE PLAN EXAMPLE: MASSACHUSETTS

Overview: Eversource Energy operates under an MRP that uses a revenue-indexing mechanism to adjust base rates, plus reconciliation of certain exogenous costs. The MRP has a five-year stay out period.

Revenue Index: Eversource's MRP allows for an adjustment of Base Rates using the rate of input price inflation representative of the electric distribution industry, less offsets for productivity and a consumer dividend.

Annual Adjustments: Effective January 1 of each year, the utility's Base Revenue Requirement is adjusted through an adjustment formula equal to the percentage change in the US Gross Domestic Product Price Inflation (GDPPI), plus a productivity adjustment of 1.56% minus a consumer dividend of 0.25%, plus an adjustment for exogenous costs.

Reconciliation of Exogenous Costs: Exogenous costs must (1) be beyond the utility's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives; (3) be unique to the electric industry as opposed to the general economy; and (4) meet a threshold of "significance" of $5 million. The utility must present supporting documentation and rationale to the commission for consideration. Once allowed by the commission, the cost is recovered or returned in a separate factor to be reviewed and approved by the commission.

Recovery of Pre-authorized Grid Modernization Costs: All grid modernization-related capital and O&M expenditures are recovered separately and are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the Grid Modernization Factor shall not exceed the preauthorized three-year budgets.

Customer Protections: Earnings Sharing provides an important protection for customers in the event that expenses increase at a rate much lower than the revenue increases generated by the MRP revenue index. If the utility's actual ROE exceeds the utility's allowed ROE by 200 basis points, 75% of any additional earnings must be shared with customers.

See: *NSTAR Electric Co. d/b/a Eversource Energy, Tariff Sheets M.D.P.U. No. 59A, filed February 16, 2018.*

2. CONTRAST TO FORMULA RATE PLANS

2.1. What is a Formula Rate Plan?

Both MRPs and formula rate plans (FRPs) feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that formula rate plans formulaically ensure that revenues track costs, often measured as deviations in ROE from the utility's target ROE. If a utility's earned return is above its ROE target, it will be required to reduce its rates. Likewise, if a utility's earned return is below its target return it will be allowed to increase its rates. In contrast, MRPs do not adjust revenues to equal costs during the plan.[4]

A report by Edison Electric Institute describes a formula rate plan as "essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service."[5] The report explains how this works as follows:

> Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated…. The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target.[6]

In other words, formula rate plans true up revenues to costs once the ROE deviates from the allowed ROE by a certain amount. These true-ups are generally accompanied by some form of commission review and approval, but these reviews are more streamlined than those that occur in a general rate case.

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[4] With the possible exception of a limited set of cost trackers or reconciliations for specific types of costs.

[5] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.

[6] *Ibid*.

ALABAMA POWER'S FORMULA RATE PLAN

Overview: Alabama Power Company operates under an FRP called the "Rate Stabilization and Equalization plan." Each year, the Alabama Public Service Commission compares the utility's projected ROE for the next year to its authorized ROE. If necessary, the utility's base rates are adjusted to keep the expected ROE within the authorized range, following a review of the reasonableness of the utility's costs.

Reconciliation Process: By December 1 of each year, the utility provides the commission with its projected ROE for the next year, together with an analysis of the main causes of any deviations from its authorized ROE and the need for any rate adjustment. During December, parties review and discuss the need for the rate adjustment, with any adjustments going into effect in January.

Customer Protections: Several customer protection measures are in place. Annual rate adjustments are capped at 5% to reduce rate shock. Once the utility's revenues are adjusted to match its projected costs for the upcoming year, the onus is on the utility to keep costs in check. If the utility fails to achieve its allowed ROE, no further reconciliation is made. However, if the utility's ROE exceeds its allowed ROE, then the excess is refunded to customers.

> ***See:*** *Laurence Kirsch and Mathew Morey, "Alternative Electricity Ratemaking Mechanisms Adopted by Other States" (Christensen Associates Energy Consulting, May 25, 2016), p. 11.*

ENTERGY ARKANSAS, INC.'S FORMULA RATE PLAN

Overview: As required by 2015 Ark. Acts 2015 725, §3, formula rate plans in Arkansas use a formula based on the difference between a utility's target and earned return. If the utility's earned return exceeds its target return by 50 basis points, it is required to reduce its rates. Likewise, if the utility's earned return falls below its target return by 50 basis points, it is allowed to increase its rates.

Cost Forecasts: The utility may choose to use a projected test year or a historical test year. If a projected test year is used, the utility must file its cost forecasts in July of each year for the next calendar year period.

Reconciliation Process: If a projected test year is used, rate changes must include an adjustment to net any differences between the prior formula rate review test period change in revenue and the actual historical year change in revenue for that same year.

Regulatory Review: The review of cost forecasts, reconciliation, and approval of new rates occurs in a 180-day process that includes a public hearing.

Customer Protections: Annual rate adjustments for each rate class are capped at 4%.

> ***See***: AR Code § 23-4-1207 (2015)

2.2. Concerns with Formula Rate Plans

Commissions have generally been reluctant to adopt formula rate plans due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with formula rate plans include "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."[7]

These concerns have been borne out by experience in jurisdictions where FRPs have been implemented. For example, in 2015, Act 725 was passed in Arkansas requiring that the Commission approve formula rate plans, but capped revenue increases under an FRP to 4% per year. Following passage of the Act, Entergy Arkansas, Inc. filed for a formula rate plan. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. As explained by the Commission Staff,

> An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility…. The ability to increase revenues 4% each year is a considerable risk reduction for the utility.[8]

More specifically the Staff noted that an FRP:

- Reduces the time afforded for review of utility costs, which can serve to incentivize spending;
- Allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on what is otherwise historical information from which to make known and measurable changes;
- Incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4% increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional regulatory tools in the Commission's toolkit are more limited under the FRP framework as the Commission has recognized;
- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4% increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.[9]

[7] Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

[8] AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019, at 17.

[9] *Id.,* at 18-19.

In its order, the Arkansas Commission agreed with Staff, stating that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."[10]

In contrast, multi-year rate plans provide strong efficiency incentives precisely by *avoiding* cost true-ups. As noted in a Brattle report filed by the Joint Utilities in Maryland, "Multi-year rate plans typically have reconciliations **more limited in scope** and typically focused on capital expenditures, **to the extent that reconciliations are included at all** [emphasis added]."[11]

FORMULA RATES AND MINNESOTA'S MRP

When Minnesota was developing its rules for multiyear rate plans, various parties proposed different approaches to revenue adjustments during the rate plan.

- The Minnesota utilities favored favor formula rates, arguing that these rates could be more useful because they would adjust to reflect the latest data.
- Other parties opposed the use of automatic formulas for the purpose of adjusting rates to reflect new costs. They argued that formula rates would reduce a utility's incentive to operate efficiently and would be burdensome to supervise. Instead, these parties favored fixed multiyear rates. The rate case would establish the rates to be charged in each year of the multiyear rate plan; the rates for the first year might differ from the rates for later years, but the base rates for all years would be known by the end of the rate case.

Ultimately the Minnesota Public Utilities Commission declined to approve multiyear rate plans that rely on formula rates, noting that such rates reduce a utility's incentive to manage its costs. Moreover, the Commission observed that formula rates are unnecessary to achieve the purpose of a multiyear rate plan, stating that "Fixed multiyear rates permit prices to adjust over time to reflect anticipated changes in a utility's circumstances, yet can be established in a fact-driven ratemaking process built on a substantial evidentiary record." Consequently, the Commission directed utilities to propose fixed rates for each year of their plan when filing a multiyear rate plan.

***See**: Minnesota Public Utilities Commission, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, June 17, 2013, at 6-7.*

[10] Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.

[11] The Brattle Group, Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates, Joint Utilities' Joint Initial Comments, Maryland PC51, March 2019.

3. ESCALATING REVENUES DURING THE MRP

Attrition relief mechanisms escalate a utility's allowed revenues over the course of an MRP. The ARM can be based on either an external price index or a cost forecast. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach. We discuss both approaches below.

3.1. Revenues Escalated Based on Cost Forecasts

An ARM based on forecasts increases revenue by predetermined percentages in each plan year based, at least in part, on a utility's cost projections. The percentages can be different in each year, or the total increase can be levelized across the years.

To determine the revenue requirement for each year, both older capital investments (i.e., depreciation expense) and new capital additions must be accounted for. Depreciation expense is straight-forward to calculate, as older capital simply continues to depreciate. As noted in a recent report published by Lawrence Berkeley National Laboratories, the controversial issue lies in estimating the value of plant additions during the plan. The report explains that shortcuts are sometimes taken when estimating plant additions. For example:

- Plant additions may be set for each plan year at the utility's average value in recent years
- Plant additions may be set for each plan year at the value calculated in the test year of the most recent rate case
- Operation and maintenance expenses can be forecasted using index-based formulas.[12]

ARMs based on cost forecasts enable the utility's revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. However, forecasted ARMs are notoriously challenging for regulators, as it is difficult to ensure that the forecasts are reasonable due to asymmetry of information.

The National Regulatory Research Institute describes this issue as follows:

> Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the

[12] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.2, https://escholarship.org/uc/item/4r13j347.

> 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.[13]

Sophisticated approaches to reducing forecast bias are available, such as the menu approach used in the United Kingdom. Under this approach, the utility can choose among various combinations of allowed revenues and earnings sharing mechanisms, such as a plan with high revenues but for which it retains only a small portion of any cost savings, or a plan with low revenues but under which it can retain a higher portion of cost savings.

Regulators may also conduct independent benchmarking and engineering studies to determine the reasonableness of cost forecasts, but such endeavors are costly. In addition, regulators can check the accuracy of past cost forecasts and create performance incentive mechanisms for forecasting accuracy. Where cost forecasts are used to set allowed revenues, they are often accompanied by a one-way (downward) reconciliation mechanism, as is done in Minnesota and New York.

MRP Based on Cost Forecasts with One-Way Reconciliations

In 2017, the Minnesota Public Utilities Commission approved a settlement regarding Xcel Energy's multiyear rate plan application. The utility's initial application requested revenue increases supported by substantial documentation of the utility's proposed cost of service. During settlement proceedings, the annual revenue requirements were adjusted downward substantially, and generally became divorced from actual project costs.

The Minnesota Commission ultimately found the settlement reasonable, despite it no longer being tied to specific project costs, as the yearly rate increases were less inflation and significantly less than what Xcel initially proposed. Further, the settlement prohibited Xcel from filing another rate case until for four years or from seeking to institute any new riders for four years.

As an additional consumer protection measure, the settlement adopted a one-way capital-spending true-up, meaning that Xcel will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. The true-up is based on aggregate capital spending, rather than individual projects. The Commission found that a true-up based on the aggregate amount of capital spending was reasonable given that Xcel's budget included approximately 1,800 capital projects. Nonetheless, the Commission also required that Xcel work with the Commission and Department of Commerce Staff to develop an annual capital-projects true-up compliance report that provides more granular data regarding project spending.

See: *Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.*

[13] Costello, "Multiyear Rate Plans and the Public Interest," 35–36.

3.2. Revenues Escalated Based on External Indexes

External indexes have historically been the preferred means by which to set a utility's allowed revenue requirements for future years of an MRP. In some cases, different categories of costs are escalated at different rates based on separate cost indexes. For example, IHS Global Insights provides cost escalation forecasts that are specific to the utility industry and are broken out by category of cost.

Indexes may be coupled with a "productivity factor." This productivity factor is often denoted as "X" and generally reflects the multifactor productivity of a group of peer utilities. In addition, a stretch factor (or "consumer dividend") may be added to the productivity factor in order to provide customers with a share of the benefit of the stronger performance incentives that are expected under the plan.[14] Further, "Y" and "Z" factors for unusual costs or costs outside of the utility's control may be added, as discussed in Section 4.1 below. The resulting escalation formula may look something like this:

$$\textit{Revenue Requirement}_{\textit{Year 2}} = \textit{Revenue Requirement}_{\textit{Year 1}} * (1 + \textit{Inflation} - X) + Y + Z$$

The California Public Utilities Commission has repeatedly rejected ARMs based on the utility's specific cost forecasts, opting instead to use inflation forecasts for different types of costs. In 2019, the California Commission adopted a capital escalation rate equal to the unweighted average of capital escalation rates across seven categories of costs, as shown in the table below:[15]

Unweighted Average of Capital Escalation Rates

	Year	
	2019	2020
Total Steam Production Plant	2.51%	2.54%
Total Hydraulic Production Plant	2.45%	2.40%
Total Other Production Plant	2.11%	2.64%
Total Transmission Plant	2.63%	2.62%
Total Distribution Plant	3.14%	3.18%
General Plant	1.82%	1.81%
Total Nuclear Palo Verde	2.55%	2.46%
Unweighted Average Across 2019-2020		**2.49%**

Escalating allowed revenues based on an external index permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based ARMs.

3.3. Conclusions Regarding Revenue Escalation Approaches

To summarize, index-based revenue adjustment mechanisms have many advantages over cost forecasts:

[14] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), 4.2, https://escholarship.org/uc/item/4r13j347.

[15] California Public Utilities Commission, D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 284.

- External cost indexes do not require that specific costs be reviewed and pre-approved at the beginning of the MRP. In contrast, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the regulator and ultimately to ratepayers. Further, it increases the administrative burden for regulators and stakeholders.
- External cost indexes do not rely on utility cost forecasts that may be subject to error or may be over-inflated.

An index-based mechanism avoids the above challenges, but still allows utility revenues to increase over the term of the MRP, allowing for longer time between rate cases, without unduly shifting risk to ratepayers.

4. Reconciliation of Costs in MRPs

Full reconciliations of costs and revenues in an MRP would be antithetical to the definition of an MRP. If revenues are trued up to equal the utility's actual costs, it erodes the utility's efficiency incentive, since the utility no longer benefits from implementing cost efficiencies and endures little risk if its costs exceed expectations. Broad annual true-ups would also essentially create annual rate cases, increasing the regulatory burden exponentially and erasing the benefits of the stay-out period.

However, some jurisdictions incorporate limited cost true-ups in MRPs. These true-ups often take the form of cost trackers for categories of costs that meet specific criteria and are limited in scope, such as costs that are outside the utility's control, or for a specific unusual capital investment.

When considering whether to implement any type of cost reconciliation mechanism, it is important to consider the impact on a utility's efficiency incentive and the impact on regulatory burden.

- If revenues are reconciled to actual costs, then the utility has reduced incentive to contain those costs.
- Under a broad reconciliation mechanism, the review required to determine that costs are reasonable imposes additional regulatory burden.

As emphasized by NRRI, "Regulators should avoid resetting annual rates based on a utility's actual cost in the absence of a prudence review…."[16] This means that any annual true-up based on actual costs would require a thorough examination of the utility's costs for prudence, which increases the regulatory burden. For these reasons, trackers and reconciliations should be used sparingly.

[16] Ken Costello, "Multiyear Rate Plans and the Public Interest," National Regulatory Research Institute, at 23.

4.1. Types of Costs that Are Often Reconciled in MRPs

In MRPs, cost reconciliations generally take some or all of the following forms:

A. Reconciliations for certain unusual, large investments
B. Reconciliations for recurring pass-through or mandated costs
C. Reconciliations or deferrals of one-time extraordinary costs

A. Reconciliations for Unusual, Large Costs ("K-Factor" Costs)

Large, unusual investments can be difficult to predict and incorporate into an MRP. Further, some investments may have impediments associated with their implementation, such as excessive risk or high capital costs. For example, the Massachusetts Department of Public Utilities found that utilities "may hesitate before making investments beyond what they deem necessary to ensure safe and reliable service, and that this reluctance may even exist "when the investments are cost-beneficial for a company but involve high capital costs, combined with regulatory lag and the potential for disallowed costs."[17]

For these reasons, large, unusual investments are sometimes addressed outside of an MRP's standard revenue requirement through a capital cost tracker or other reconciliation mechanism, often generically referred to as a "K-factor." In Massachusetts, such a factor was established for certain "foundational" grid modernization investments, as discussed in the box below.

[17] Massachusetts Department of Public Utilities, Order D.P.U. 12-76-A, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, December 23, 2013, at 25. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637

Reconciliation of Grid Modernization Costs in Massachusetts

Utilities may hesitate before making investments with high capital costs, particularly when combined with regulatory lag and the potential for disallowances. To encourage grid modernization, the commission in Massachusetts approved a targeted cost recovery mechanism called the "Grid Modernization Factor" or "GMF" for investments that are preauthorized by the commission.

Pre-authorization of investments and budgets: All grid modernization-related capital and O&M expenditures are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the GMF shall not exceed the preauthorized three-year budgets.

Cost Recovery: Costs are only eligible for recovery after the expenses have been incurred and the investments have been placed in service. The utilities file annual GMF rate adjustment and reconciliation filings comprised of: (1) actual, eligible preauthorized expenditures from the prior grid modernization plan investment year; and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement is calculated on the average monthly balance using the customer deposit rate.

Annual Reconciliation Filings: On an annual basis, the utilities must file testimony and supporting exhibits with full project documentation of all grid modernization capital projects placed into service during the plan investment year and documentation of O&M expenses. The utilities must demonstrate that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable). Additionally, the filing shall also describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed factors are calculated appropriately, and provide bill impact estimates.

See: *Massachusetts Department of Public Utilities, Order D.P.U. 15-122, May 10, 2018, at 216-235. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163507*

B. Reconciliations for Recurring Pass-Through or Mandated Costs ("Y-Factor" Costs)

Recurring costs that are volatile and outside of utility control may be fully or partially reconciled during an MRP using cost trackers or deferral mechanisms. In Alberta, these costs are referred to as "Y-Factor" costs. The Alberta Commission established the following criterial for costs eligible for Y-Factor treatment:

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the [MRP revenue] formulas.
4) The costs must be prudently incurred.

5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.[18]

New York allows reconciliations only for costs that "are difficult to forecast with certainty and are largely beyond the direct control of utility management."[19] In New York, reconciliation and/or deferral accounting mechanisms have been used for costs including:

- Taxes
- Pensions/other post-employment benefits (OPEBs)
- Environmental remediation costs
- Regional Greenhouse Gas Initiative ("RGGI") costs
- System Benefits Charges
- Energy Efficiency Portfolio Standard charges and Demand Side Management costs
- New York Public Service Law §18-a regulatory assessment (for commission costs)
- Market supply charges
- Cost of the Low Income customer charge discounts[20]

We note, however, that some of these reconciliations have been only partial in order to preserve some incentive for the utility to manage the costs efficiently. In Consolidated Edison's MRP, if property taxes varied in any Rate Year from the projected level provided in rates, only 80% of the variation would be deferred and either recovered from or credited to customers, subject to a cap on the Company's share equal to 10 basis points on common equity for each Rate Year.[21]

In its order approving ConEdison's MRP, the New York Public Service Commission explained that asymmetrical and partial reconciliations for certain costs "provide the Company an incentive to manage such costs to the extent practicable." The Commission further noted that such reconciliation provisions decrease the volatility of a company's earnings and transfer risk to ratepayers, which allows the Commission to reduce the allowed return on equity in rate proceedings. The Commission explains that this "is one of the prime reasons returns allowed in New York are and can be lower than those in many other jurisdictions."[22] It is reasonable that any reconciliations and reduced risk to the utility be accompanied by a commensurate reduction in the utility's allowed ROE.

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[18] Alberta Utilities Commission, Decision 2012-237, September 12, 2012, at 135.

[19] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 26. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}

[20] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014.

[21] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 18.

[22] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.

C. Reconciliations of One-Time Extraordinary Costs ("Z-Factor Costs")

In an MRP, true-ups can be appropriate for exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably (such as extraordinary storm response costs). For example,

- New York's MRPs allowed cumulative major storm damage expenses in excess of a certain threshold to be deferred. The expenses would be subject to New York Department of Public Service Staff review.[23]

- California has utilized "Z-factors" to reconcile items that meet the following criteria:
  1. The event must be exogenous to the utility;
  2. The event must occur after implementation of rates;
  3. The costs are beyond the control of the utility management;
  4. The costs are a normal part of doing business;
  5. The costs must have a disproportionate impact on the utility;
  6. The costs and event are not reflected in the rate update mechanism;
  7. The costs must have a major impact on overall costs;
  8. The cost impact must be measurable; and
  9. The utility must incur the cost reasonably.[24]

4.2. One-Way Reconciliations of Costs

As discussed above, the most common means of adjusting allowed revenues during the rate plan is the index approach. However, some jurisdictions use cost forecasts, or a combination of external indexes and cost forecasts. Where cost forecasts are used, they are frequently accompanied by one-way (downward) reconciliations of costs.

A key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections. As the Alberta Public Utilities Commission noted, unless there is a reconciliation mechanism, basing revenues on cost forecasts "creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable." Further, the Alberta Commission notes its "concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives…"[25]

A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation

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[23] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 24.

[24] California Public Utilities Commission, D1408032, Authorizing PG&E's GRC Revenue Requirement for 2014-2016, at 661.

[25] Alberta Utilities Commission, Decision 20414-D01-2016, December 16, 2016, at 53.

also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudency review in the subsequent rate case. However, the one-way nature of the reconciliation still incentivizes the utility to inflate its capital projections to ensure that it does not exceed its capital cost forecast. Just as importantly, it provides no incentive to increase efficiency.[26]

Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments, but have coupled the forecasts with a one-way (downward) reconciliation mechanism. New York's approach is discussed in the box below.

New York's "Claw-Back Mechanism"

A one-way reconciliation mechanism is used in New York and referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission describes this mechanism for Consolidated Edison as follows:

> If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance…, the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.

See: *New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.*

[26] The California Public Utilities Commission (CPUC) has objected to such claw-back mechanisms precisely because it erodes the utility's incentive to be efficient. The CPUC explains:

> "…we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate 'give backs' of all cost savings to ratepayers. If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality."

See: California Public Utilities Commission, D.85-03-042, 17 CPUC2d 246, at 254, as cited in D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 152.

5. OTHER COMPONENTS OF MRPS

5.1. Earnings Sharing Mechanisms

Earnings sharing mechanisms are primarily implemented to ensure that utility earnings do not become excessive during multi-year rate plans. The vast majority of these earnings sharing mechanisms are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with customers. As noted by the Brattle Group, earnings sharing mechanisms that apply to "utility over earnings (but not under earnings) are in place in 10 states."[27] Only one state (Hawaii) is considering an earnings sharing mechanism for under-earnings as well.

Four states with MRPs have no earnings sharing mechanisms at all, allowing the utility to retain all over-earnings or suffer any under-earnings. Where earnings sharing mechanisms are used, there is the risk that the utility's efficiency incentives will be blunted. Thus, to preserve utility incentives, many of the states with earnings sharing mechanisms also apply a deadband where a utility is not required to share excess earnings with customers.

In Massachusetts, the deadband for earnings sharing is 200 basis points for Eversource. If the utility's ROE exceeds its allowed ROE by 200 basis points, it must return 75% of additional earnings (beyond 200 basis point) to ratepayers. In Iowa, the commission set MidAmerican's allowed ROE at 10% and then required that earnings between 11% and 14% be shared 80% with ratepayers. Beyond an earned ROE of 14%, all of the excess earnings are to be returned to ratepayers.[28]

5.2. Rate Plan Duration

MRPs are usually last between three and five years, although the plans in the United Kingdom last for eight years. There are several distinct advantages to plans that are shorter in duration:

- Shorter plans require less up-front investment in time and resources (modeling, review).
- Shorter plans present less risk associated with getting the forecasts wrong.

However, shorter plans also provide much weaker incentives for a utility to reduce its costs, as any cost reductions will quickly pass on to ratepayers at the time of the next rate case (unless efficiency carryover mechanisms are used).[29]

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[27] Pepco Exhibit J, Witness Zarakas, in FC 1156, The Application of the Potomac Electric Power Company Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia, at 13.

[28] Iowa Utilities Board, Order Approving Settlement, with Modifications, and Requiring Additional Information, Docket No. RPU-2013-0004, March 17, 2014.

[29] Efficiency carryover mechanisms allow for the utility to retain a share of its savings from efficiency improvements for a set period of time when a multiyear rate plan expires. For more information, see Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.8-4.10, https://escholarship.org/uc/item/4r13j347.

In contrast, longer plans provide greater innovation incentives (due to more time for utility to reap rewards from innovation and efficiencies). Longer plans also reduce the frequency of rate cases and therefore possibly reduce overall costs of regulation.

5.3. Reopener Provisions

Reopeners permit a reassessment of the utility's revenues and costs with the potential to make adjustments. A utility would be expected to request a reopener if it was under-earning, while a regulator or other stakeholder would be expected to request a reopener if they felt the utility was over-earning. However, use of reopeners can dilute incentives for the utility to operate efficiently, since the utility knows it can simply come back in and ask for more revenues, or the utility knows that if it operates too efficiently, its higher earnings will be taken away prematurely. Establishing clear criteria for reopening rate plans at the outset can help avoid reopening rate plans except when absolutely necessary.

In Minnesota, a utility that receives Commission approval of its multiyear rate plan must delay filing a new rate case until after the plan expires. However, utilities still retain the discretion to request rate relief from the Commission under Minn. Stat. § 216B.16, subd. 19 (c).

5.4. Performance Incentive Mechanisms

Under an MRP regulatory framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with performance incentive mechanisms (PIMs) to prevent service quality degradation. Increasingly, PIMs are also increasingly being used to promote other outcomes, such as emissions reductions, as well as to ensure that a utility follows through on its commitments, such as investments in grid modernization.