NEW REGULATORY FINANCE

Roger A. Morin, PhD

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The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \qquad (6\text{-}5)$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$\begin{aligned} K &= 5\% + 0.25\ (12\% - 5\%) + 0.75 \times 0.80\ (12\% - 5\%) \\ &= 5.0\% + 1.8\% + 4.2\% \\ &= 11.0\% \end{aligned}$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

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State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

July 2017

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DISCLAIMER

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July 2017

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Executive Summary

Berkeley Lab published a report in 2016 that discussed two approaches to performance-based regulation (PBR) of electric utilities: multiyear rate plans (MRPs) and performance incentive mechanisms (PIMs).[1] The authors described these approaches at a high level and in the context of growing levels of demand-side management (DSM), distributed generation and other distributed energy resources (DERs).

This report presents a more in-depth analysis of the multiyear rate plan approach to PBR for electric utilities, applicable to both vertically integrated and restructured states. The report is aimed primarily at state utility regulators and stakeholders in the state regulatory process. The approach also provides ideas on how to streamline oversight of public power utilities and rural electric cooperatives by their governing boards.

We discuss the rationale for MRPs and their usefulness under modern business conditions. We then explain critical plan design issues and challenges and present results from numerical research that considers the extra incentive power achieved by MRPs with different plan provisions. Next, the report presents several case studies of utilities that have operated under formal MRPs or, for various reasons, have stayed out of rate cases for more than a decade. In these studies we consider the effect of MRPs and rate case frequency on utility cost, reliability and other performance dimensions. Appendices present further information on MRP plan design and some details of the technical work.

What Are MRPs?

MRPs are a comprehensive approach to PBR designed to strengthen general incentives for good utility performance. Two key provisions of MRPs strengthen cost containment incentives and streamline regulation:

1. A rate case moratorium reduces the frequency of rate cases, typically to once every four or five years.

2. An attrition relief mechanism (ARM) escalates rates or revenue between rate cases to address cost pressures such as inflation and growth in number of customers independently of the utility's own cost.

Loosening the link between its own cost and revenue gives a utility an operating environment more like that which competitive markets experience.

Most MRPs feature a performance metric system that includes some PIMs. These PIMs provide awards or penalties, or both, for performance in targeted areas. PIMs are most commonly used in MRPs to strengthen incentives for utilities to maintain or improve reliability and customer service quality. Some plans also include earnings sharing mechanisms, efficiency carryover mechanisms and marketing flexibility.

Provisions are often added to plans to strengthen utility incentives for DSM. For example, utility expenditures on DSM programs are usually tracked, and PIMs can be added to reward utilities for successful DSM programs. Revenue decoupling can mitigate a utility's incentive to boost retail sales and reduce risks of revenue losses from rate designs that encourage DSM.

[1] Lowry and Woolf (2016).

How Prevalent Is This Approach?

MRPs were first widely used in the United States in the 1980s to regulate railroads and telecommunications carriers, industries beset by rising competition. Early adopters of MRPs in the U.S. electric utility industry included California and several northeastern states. Use of MRPs has recently grown among vertically integrated electric utilities in diverse states that include Arizona, Georgia and Washington. Greater use of MRPs for power distributors has been slowed by their requests for accelerated system modernization, which complicate plan design. MRPs are much more common for electric utilities in Canada and countries overseas. The impetus for adopting MRPs in these countries has often come from policymakers rather than utilities.

What Is the Rationale for These Plans?

America's investor-owned electric utility industry was largely built under cost of service regulation (COSR). This regulatory system traditionally adjusted rates that compensate utilities for costs of capital, labor and materials only in general rate cases. The scope of costs eligible for tracker treatment, which expedites cost recovery, has gradually enlarged and sometimes includes capital costs as well as energy expenditures.

The efficacy of COSR varies with external business conditions. When conditions favor utilities (e.g., are conducive to realizing at least the target rate of return), rate cases are infrequent. Performance incentives are then strong and the cost of regulation is quite reasonable. When conditions are less favorable, rate cases are more frequent and more costs are tracked. Performance incentives can then be weak and regulatory cost can be high. These attributes of COSR are worrisome because business conditions today are often less favorable to utilities than in the past.

MRPs are a different approach to regulation that is especially appealing when the alternative is frequent rate cases or expansive cost trackers. The regulatory process is streamlined and better utility performance can be encouraged due to stronger performance incentives and increased operating flexibility. Benefits of better performance can be shared with customers. Recent advances in MRPs such as efficiency carryover mechanisms and statistical benchmarking can "turbocharge" their incentive power and ensure benefits for customers.

What Are Some Disadvantages of MRPs?

MRPs are complex, and their adoption can involve extensive change to the regulatory system. It can be challenging to design plans that strengthen incentives without undue risk and share benefits fairly between utilities and their customers. Some kinds of business conditions (e.g., brisk inflation and declining average use) have proven easier to address using MRPs than others (e.g., capital spending surges). MRPs can invite strategic behavior and controversies over plan design.

Case Studies

This report discusses six case studies of utilities operating under MRPs:

1. Central Maine Power operated under a sequence of MRPs from 1996 to 2013. The plans afforded the company unusual marketing flexibility which it used to develop special contracts with large-volume customers. These contracts helped the company retain their contributions to fixed costs of the system, for the benefit of all customers.

2. California has the nation's longest history with MRPs for retail services of electric utilities. The Public Utilities Commission has limited rate case frequency and staggered plan terms to avoid simultaneous rate cases. Plan provisions have provided strong incentives for utilities to embrace DSM.
3. New York has regulated electric utilities using MRPs since the 1990s. The state's Reforming the Energy Vision proceeding has considered how rate plans should evolve to regulate the "utility of the future."
4. MidAmerican Energy operated under a rate freeze in Iowa from 1997 to 2013. This freeze extended to charges for energy procured as well as for capital, labor and materials.
5. Ontario, Canada, has used MRPs to regulate the dozens of power distributors since the late 1990s. Capital spending surges have posed special plan design challenges. Innovations in Ontario regulation also include incentive-compatible menus and extensive use of benchmarking.
6. Great Britain also has a long history with MRP regulation. The current "RIIO" approach to regulation of energy utilities there has attracted the attention of many North American regulators.

Impact on Cost Performance

This report also addresses the impact of MRPs (and, more generally, rate case frequency) on utility cost performance using two analytical tools: incentive power analysis and empirical research on utility productivity trends. An Incentive Power Model uses numerical analysis to assess the incentive impact of alternative stylized regulatory systems. For North American case studies, we compared productivity trends of utilities operating under MRPs to U.S. norms. We also considered productivity trends of utilities that operated under unusually frequent and infrequent rate cases.

Both lines of research suggest that the frequency of rate cases can materially affect utility cost performance. For example, the multifactor productivity (MFP) growth of the electric, gas and sanitary sector of the U.S. economy was materially slower than that of the economy as a whole from 1974 to 1985, when rate cases were frequent due in part to adverse business conditions, than in the early postwar period, when favorable business conditions encouraged less frequent rate cases. We also found that the MFP growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs.

Conclusions

The case studies and incentive power and productivity research presented in this report have important implications. First, utility performance and regulatory cost should be on the radar screen of U.S. regulators, consumer groups and utility managers. Our research shows that key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR worked well and was becoming a tradition. Today's conditions encourage more frequent rate cases and more expansive cost trackers. MRPs can produce material improvements in utility performance which can slow growth in customer bills and bolster utility earnings.

Notwithstanding the potential benefits of MRPs, they are still not used in most American states. COSR is well established and there are many accomplished practitioners. It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design. Continuing innovation of COSR will occur, and this will slow diffusion of MRPs.

However, MRPs are also evolving and remedies to problems encountered in early plans have been developed. MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER penetration and increased need for marketing flexibility. For these and other reasons, we foresee expanded use of MRPs in U.S. electric utility regulation in coming years.

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Glossary of Terms

Attrition Relief Mechanism (ARM): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital. Base rates sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

Earnings Sharing Mechanism (ESM): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism: A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Formula Rate Plan: An approach to ratemaking that uses cost of service formulas to cause a utility's revenue to track its own cost of service closely. This is sometimes accomplished with an earnings true-up mechanism that adjusts rates automatically to eliminate variances between a company's actual and target rate of return on equity. Review of the cost of service may be streamlined.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for base rate revenue lost from specific causes such as demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to discourage predation and cross-subsidization.

Multiyear Rate Plan (MRP): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Productivity: The efficiency with which a utility converts inputs to outputs, commonly measured by productivity indexes. Labor, operation and maintenance, capital and multifactor productivity are commonly measured. Industry productivity trends are often used in the design of ARMs.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes. Rate base includes "working capital" — cash the utility must have available to meet the current cost of operations given the lag between customers receiving electric service and when they pay their electric bills. Regulators may allow other adjustments.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce or eliminate the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on the operations of utilities to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

X Factor (Productivity Factor): A term in a rate or revenue cap index that reflects the impact of productivity growth on cost growth. It may also incorporate stretch factors and adjustments for other considerations such as the inaccuracy of the inflation measure.

Z Factor: A term in a rate or revenue cap index that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are beyond the utility's control.

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1.0 Introduction

The electric utility industry has made significant contributions to the success of the U.S. economy over the years. Rates and service quality of electric utilities affect both household welfare and the competitiveness of business and industry. The large role played by many U.S. utilities in power generation magnifies their importance.

Utilities today must contain cost growth at a time when many need to modernize aging systems. Major changes are occurring in technologies, customer preferences, load growth, competitive challenges, and federal and state policies and regulations. Most electric utility facilities in the United States are investor-owned and subject to rate and service regulation by state public utility commissions. Regulatory systems under which these utilities operate affect their performance and ability to meet challenges.

Multiyear rate plans have some advantages over traditional rate regulation in today's business environment. This is a form of performance-based regulation (PBR) that suspends general rate cases for several years. Revenue growth between rate cases is to some degree predetermined and independent of a utility's own cost. Better utility performance can sometimes be achieved under MRPs while achieving lower regulatory costs.[2] Benefits can be shared between utilities and their customers. However, plans are complex and their adoption can involve sizable changes in the regulatory system. Designing plans that stimulate performance without undue risk and share benefits fairly can be challenging.

Berkeley Lab prepared a report on PBR in 1995, when it was just beginning.[3] The study appraised some approved PBR plans using an "incentive power index." Thoughtful commentary on PBR included prescient discussion of revenue decoupling, which is now widely used in utility regulation. In 2016, Berkeley Lab published a report comparing MRPs to another popular approach to PBR — targeted performance incentive mechanisms — in the context of growing levels of distributed energy resources.[4] The report focused on advantages and disadvantages from utility shareholders' and customers' perspectives.[5]

This report takes a closer look at MRPs for electric utilities:

- how and where they have been applied to electric utilities in the United States and other countries;
- key plan design and implementation issues;
- metrics used to evaluate and incentivize utility performance; and
- successes, failures and lessons learned.

The focus is on retail services, such as power supply, distribution and customer care, which are regulated by states.

[2] The impact of PBR on the performance of cooperative and publicly owned utilities is not well understood. However, PBR provides ideas on how to streamline regulation of these utilities. Numerous publicly owned utilities in other countries have operated under PBR.
[3] Comnes et al. (1995).
[4] The report explained that energy efficiency, demand response, and distributed generation and storage can help contain costs of meeting America's energy needs, but can reduce utility earnings.
[5] Lowry and Woolf (2016).

While the authors of the 1995 Berkeley Lab study anticipated restructuring of retail U.S. power markets, vertically integrated electric utilities (VIEUs) still serve retail customers in many states. This report thus considers the situations of VIEUs as well as those of the utility distribution companies (UDCs) that serve regions with restructured retail power markets. The report also provides results from an incentive power model and research on trends in the productivity with which utilities provide their services.

Section 2 of this report provides an introduction to MRPs. Section 3 considers rationales for MRPs and their suitability for electric utilities today. Section 4 drills down into important issues in MRP design. Section 5 discusses results of our research on the incentive power of alternative regulatory systems. Section 6 presents several case studies, and Section 7 discusses lessons learned. Two appendices discuss some topics in greater detail.

2.0 Multiyear Rate Plans

2.1 The Basic Idea

PBR is an approach to utility regulation designed to encourage good performance using strong performance incentives. Multiyear rate plans are a common form of PBR around the world. Berkeley Lab's 2016 report discussed basic features of these plans.[6] General rate cases are typically held every four or five years. Between rate cases, an attrition relief mechanism (ARM) permits revenue (or rates) to grow in the face of cost pressures, without linking relief to a utility's *specific* costs.[7] Some costs may be addressed separately using cost trackers and associated rate riders.

Following is a generic formula for revenue escalation in a multiyear rate plan:

$$growth\ Revenue = growth\ ARM + Y + Z. \qquad [1]$$

The "Y factor" indicates the revenue adjustment for costs, such as fuel and purchased power expenses, which are chosen in advance for tracking treatment. The "Z factor" indicates the revenue adjustment for miscellaneous changes in cost which may occasionally be accorded tracker treatment. The Z factor may address cost changes due to miscellaneous factors outside utility control, such as government mandates (e.g., facility undergrounding requirements) and force majeure events such as severe storms.[8]

MRPs also typically feature performance metric systems. Some metrics provide the basis for targeted performance incentive mechanisms (PIMs) that aid measurement of performance in areas of special concern to customers and the public. Most commonly, PIMs are used to strengthen incentives for utilities to maintain or improve reliability and customer service quality. A broader range of metrics has recently been considered by regulators in several jurisdictions, including Great Britain and New York.[9]

Demand-side management (DSM) can lower the cost of meeting customer energy needs. MRPs often contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked.[10] Performance incentive mechanisms can reward utilities for successful DSM programs. Revenue decoupling is often added to sever short-term links between a utility's revenue and electricity sales.[11] This shifts the risk of fluctuations in system use to customers but reduces utility incentives to boost throughput between rate cases. Decoupling also reduces the risks of rate designs that encourage DSM and efficient customer-side distributed generation and storage.

Some MRPs feature earnings sharing mechanisms (ESMs) that share surplus or deficit earnings, or both, between utilities and their customers, which result when the rate of return on equity (ROE) deviates from its public utility commission-approved target.[12] Off-ramp mechanisms may permit review of a plan under prespecified outcomes such as extreme ROEs.

Some MRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Utilities also may be permitted (or required) to gradually redesign rates for

[6] Lowry and Woolf (2016).
[7] To simplify the discussion, this report will provide illustrations only for revenue cap escalators.
[8] Z factors are discussed further in Appendix A2.
[9] Ofgem (2014) and New York Public Service Commission (2016a).
[10] Institute for Electric Innovation (2014).
[11] Lazar et al. (2016).
[12] Earnings sharing mechanisms are discussed further in Appendix A1.

standard services in fulfillment of commission-approved goals. Marketing flexibility is discussed further in Appendix A.

Plan review and termination provisions are also important in MRPs. Some plans provide for a midterm review of the MRP toward the end of the plan period. These reviews sometimes result in a plan extension without a general rate case. To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited if the plan ends with a rate case. For example, the utility may be permitted to keep a share of the difference between its cost and a cost benchmark. Provisions of the latter kind are sometimes called *efficiency carryover mechanisms.*

2.2 MRP Precedents

MRPs have been used in U.S. rate regulation since the 1980s. They were first used on a large scale for railroads and telecommunication carriers.[13] These companies faced significant competitive challenges that complicated regulation. MRPs streamlined regulation and afforded utilities more marketing flexibility and a chance to earn a superior return for superior performance. Some states still use MRPs to regulate services of telecommunication carriers in less competitive markets.[14] The Federal Energy Regulation Commission (FERC) uses MRPs to regulate oil pipelines.[15]

MRPs have been used in several states to regulate retail services of natural gas and electric utilities.[16] In addition to formal rate plans, several states established extended rate freezes for electric utilities during the transition to retail competition. Rate freezes also have been part of the ratemaking treatment for many mergers and acquisitions. Utilities have occasionally and for various other reasons managed to stay out of rate cases for periods exceeding a decade.

Figure 1 shows states that currently use MRPs to regulate retail services of U.S. electric and gas utilities. The figure shows that MRPs are more common for U.S. electric utilities than for gas distributors. Growth in the use of MRPs to regulate electric power distributors has been slowed by grid modernization challenges that complicate plan design. On the other hand, use of MRPs has recently spread to vertically integrated electric utilities in diverse states that include Arizona, Colorado, Georgia, Virginia and Washington. This reflects in part the slowdown and increased predictability of VIEU cost growth in an era when there is less need for large generation plant additions. Many states also have recently experimented with "mini" MRPs involving only two plan years.

Figure 2 shows that MRPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MRPs are the norm in Australia, Ireland, New Zealand and the United Kingdom. Countries that use MRPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania and Sweden. MRPs are also common in Latin America.

The impetus for adopting MRPs outside the United States has often come from policymakers rather than utilities. For example, provincial law in Quebec requires the Régie de l'Energie to use an approach to regulation which streamlines regulation, encourages continual performance gains and shares benefits

[13] A discussion of early railroad and telecommunication MRPs can be found in Lowry and Kaufmann (2002).
[14] See, for example, California Public Utilities Commission (2015a), and Vermont Public Service Board (2016).
[15] Federal Energy Regulatory Commission (2015).
[16] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. The latest is Lowry et al. (2015).

fairly with customers.[17] The Régie recently ordered Hydro-Quebec to operate its power distributor services prospectively under an MRP that the company had opposed.[18]

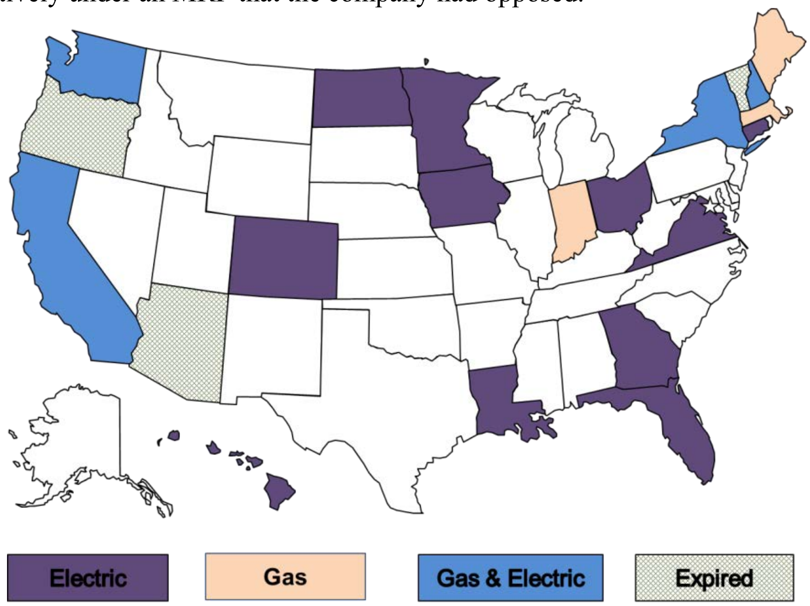

Figure 1. Multiyear Rate Plans in the United States. MRPs are used in many states today to regulate utilities.

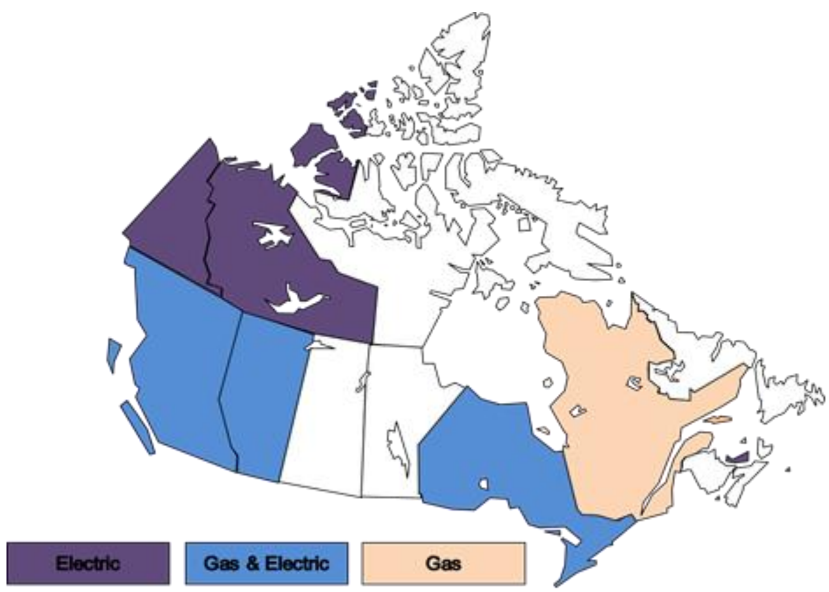

Figure 2. Multiyear Rate Plans in Canada. MRPs have in recent years been used to regulate energy utilities in the most populous Canadian provinces.

[17] Quebec National Assembly (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed 14 June, 2013.
[18] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 7, 2017.

3.0 Rationale for Considering MRPs

To explain rationales for considering MRPs we first consider basic features of traditional cost of service regulation (COSR) approaches which are widely used in the United States and then discuss reasons that some jurisdictions have adopted MRPs. We conclude with a discussion of circumstances under which PBR may make sense for some electric utilities under today's business conditions.

3.1 Traditional Cost of Service Regulation

Under COSR,[19] base rates that address costs of capital, labor and materials are reset periodically in rate cases to more effectively recover the utility's cost of service. Rate cases usually occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue is drawn from usage charges — e.g., charges per kilowatt-hour (kWh) or kilowatts (kW) of system use. The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (e.g., the capacity to serve peak load and to deliver to multiple locations) than by growth in system use. The number of customers served is highly correlated with peak load and an important cost driver in its own right. [20,21] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (average use). Earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining value of older assets due to depreciation and capital expenditures to replace aging infrastructure.

The regulatory cost of COSR is high (for utilities, public utility commissions and stakeholders) when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that the jurisdiction regulates numerous utilities or the operating conditions facing utilities are continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

Regulators understandably take measures to contain regulation's costs. Some of these measures may have adverse consequences. For example, expanded use of cost trackers and a reduced scope for prudence reviews weaken utility incentives to cut costs.[22] Because frequent rate cases and expansive cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

[19] Bonbright et al. (1988) is an authoritative treatise on COSR. Lowry and Woolf (2016) provides a more extensive discussion of COSR than provided here, emphasizing incentive problems.
[20] This is because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.
[21] DSM programs can alter this relationship but to date have had more effect on delivery volumes than they have on the peak demand that drives capacity growth.
[22] Cost trackers have the merit of reducing the need for general rate cases.

Regulatory Lag

Regulatory economists acknowledge the incentive problems with traditional regulation that arise when rate cases are frequent or cost trackers are expansive. In the literature, "regulatory lag" is commonly defined as the time period between the moment when a utility's cost changes and the moment when there is a commensurate change in its rates.[23] James Bonbright, for example, states in a classic treatise that:

> There is the so-called "regulatory lag" — the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.[24]

The ability of regulatory lag to strengthen a utility's incentive to contain costs has been discussed in the literature. For example, Bonbright states that:

> Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the regulatory lag as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.[25]

Another noted regulatory economist, Alfred Kahn, suggested that:

> Public utility commissions ought not to even *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return; and they probably ought not to try either to hold the rate of return down to the bare cost of capital. The *regulatory lag* — the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low — is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[26] [emphasis in original]

Under traditional regulation, regulatory lag also delays when rates are changed in response to increasing *external* cost pressures such as input price inflation. For this reason, utility executives and consumer advocates have both emphasized regulatory lag in their rate case evidence despite goals that are often in opposition.

[23] Alternative definitions of "regulatory lag" have been used. One is the period of time between the filing of a request for a rate increase and the increase in rates.
[24] Bonbright et al. (1988).
[25] Ibid., p. 198.
[26] Kahn (1988), p. 48 II.

The Utility Productivity Slowdown of 1973–1986

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity growth reflects changes in diverse business conditions that affect cost, including technological change and realization of scale economies. A multifactor productivity (MFP) index typically considers productivity in use of capital, labor and materials. Appendix B.2 discusses productivity more extensively.

One way to gauge the importance of regulatory lag is to compare utility productivity growth in years when business conditions for utilities were favorable to the growth in years when conditions were unfavorable. Since rate cases tend to be more frequent and cost trackers more expansive when business conditions are unfavorable, productivity growth should be slower. The federal government calculated an index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[27] We can consider the growth rate of this index during periods of favorable and unfavorable business conditions.

Table 1 presents evidence on two of the most important sources of potential financial attrition for electric and natural gas utilities:

- Trends in the average use of energy by residential and commercial customers
- Price inflation, measured here by the gross domestic product price index (GDPPI)[28]

Average use directly affected MFP growth as measured by the government, but inflation did not.

We constructed summary indicators of potential attrition facing gas and electric utilities. The indicator in each case is the difference between inflation and the average of the growth in average use of energy (gas or electricity) by residential and commercial customers. We report trends over several subperiods between 1927 and 2014.

Results for electric utilities, where data are available for more years, show that these business conditions were quite favorable on balance from the late 1920s until the early 1970s. Except in the 1940s, inflation was generally slow until the late 1960s.[29] Average use of electricity grew rapidly.

These business conditions grew dramatically more adverse for electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities such as coal and gas was especially rapid. Combined with slower economic growth, this caused growth in the average use of power by residential and commercial electric customers to slow markedly.

Rate cases were much more frequent.[30] Table 2 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[31] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

[27] Computation of this index ended in 1998. For a discussion of this research, see Glaser (1993), pp. 34–49.
[28] The GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.
[29] Rapid inflation during the Korean War was offset by slower inflation in later years of the 1950s.
[30] See Joskow and MacAvoy (1975).
[31] Braeutigam and Quirk (1984), p. 47.

Table 1. Indicators of Energy Utility Financial Attrition in the United States (1927–2014)

	Average Annual Electricity Use					Average Annual Natural Gas Use					GDPPI Inflation[4]		Summary Attrition Indicators	
	Residential[1]		Commercial[1]		Average	Residential[2]		Commercial[3]		Average				
	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Electric	Natural Gas
Multiyear Averages					[A]					[B]		[C]	[C]-[A]	[C]-[B]
1927-1930	478	7.06%	3,659	6.67%	6.86%	NA	NA	NA	NA	NA	9.71	-3.92% [5]	-10.79%	NA
1931-1940	723	5.45%	4,048	2.00%	3.73%	NA	NA	NA	NA	NA	7.99	-1.59%	-5.31%	NA
1941-1950	1,304	6.48%	6,485	5.08%	5.78%	NA	NA	NA	NA	NA	11.37	5.26%	-0.52%	NA
1951-1960	2,836	7.53%	12,062	6.29%	6.91%	NA	NA	NA	NA	NA	16.04	2.42%	-4.49%	NA
1961-1972	5,603	5.79%	31,230	8.79%	7.29%	125	1.78% [6]	726	3.97% [6]	2.88% [6]	20.35	2.98%	-4.32%	0.10% [7]
1973-1980[8]	8,394	2.03%	50,576	2.53%	2.28%	117	-2.22%	764	-0.63%	-1.42%	34.74	7.18%	4.90%	8.61%
1981-1986[8]	8,820	0.12%	54,144	0.81%	0.46%	98	-2.67%	651	-3.84%	-3.26%	54.22	4.57%	4.11%	7.82%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%	93	-1.25%	631	1.33%	0.04%	63.32	3.33%	1.49%	3.29%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%	88	-0.37%	639	0.30%	-0.04%	75.70	2.03%	0.62%	2.07%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%	77	-2.12%	594	-1.55%	-1.83%	89.83	2.47%	1.79%	4.30%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%	72	0.58%	597	1.75%	1.17%	103.53	1.60%	1.90%	0.43%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, Historical Natural Gas Annual 1930 Through 1999 (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014).

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers, Revised October 28, 2016.

[5] Growth rate is for 1930 only. Levels are for 1929 and 1930. Data are not available before 1929.

[6] Levels are for 1967-1972 and growth rates are for 1968-1972. Data are not available before 1967.

[7] Note that the growth rates used to compute this value cover different periods.

[8] Shaded years had unusually unfavorable business conditions.

Table 2. U.S. Electric Utility Rate Cases: 1948–1977[32]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

After 1986, inflation slowed to a pace more typical of the 1950s and 1960s. However, sluggish growth in average use continued. Thus, business conditions improved on balance, but were less favorable than those in the decades preceding the first oil price shock.[33]

Table 3 and Figure 3 show the trend in the federal government's index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1948 to 1998. The MFP growth of the sector was remarkably brisk until the early 1970s, averaging 3.9 percent annually compared to the 2.1 percent trend in the MFP of the entire private business sector of the economy.

[32] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potential excessive utility earnings.
[33] Average use data for a comparably long period were not found for natural gas distributors. However, average use of natural gas fell briskly during the 1973 to 1986 period, whereas it had risen briskly from 1968 to 1972. Inflation and average use trends were thus extremely unfavorable for gas distributors from 1973 to 1986. While inflation slowed after 1986, declining average use continued so that, on balance, business conditions improved for gas distributors but were less favorable than in the 1960s.

Table 3. Multifactor Productivity Growth of Electric, Gas, and Sanitary Utilities and the U.S. Private Business Sector: 1949–1998

	Electric, Gas, and Sanitary Utilities[1]		U.S. Private Business Sector[2]		MFP Growth Differential
	Level	Growth Rate	Level	Growth Rate	
Year		[A]		[B]	[A - B]
1948	34.67		50.34		
1949	35.23	1.60%	50.93	1.16%	0.45%
1950	37.85	7.16%	54.63	7.03%	0.14%
1951	41.50	9.19%	55.90	2.29%	6.90%
1952	43.27	4.19%	56.39	0.87%	3.32%
1953	44.95	3.81%	57.66	2.22%	1.59%
1954	46.73	3.87%	57.76	0.17%	3.71%
1955	50.37	7.51%	60.49	4.62%	2.89%
1956	52.90	4.89%	60.20	-0.49%	5.37%
1957	54.86	3.64%	61.07	1.45%	2.19%
1958	56.36	2.69%	61.37	0.48%	2.21%
1959	59.91	6.11%	63.51	3.44%	2.67%
1960	61.68	2.92%	63.90	0.61%	2.31%
1961	63.18	2.40%	65.27	2.11%	0.28%
1962	66.26	4.77%	67.61	3.52%	1.24%
1963	67.57	1.96%	69.66	2.99%	-1.03%
1964	71.12	5.12%	72.39	3.85%	1.28%
1965	74.02	3.99%	74.73	3.18%	0.81%
1966	77.01	3.96%	76.98	2.96%	1.00%
1967	79.44	3.11%	77.07	0.13%	2.98%
1968	82.99	4.37%	79.12	2.62%	1.75%
1969	85.23	2.67%	78.63	-0.62%	3.29%
1970	86.64	1.63%	78.54	-0.12%	1.76%
1971	87.66	1.18%	80.98	3.06%	-1.88%
1972	89.16	1.69%	83.41	2.97%	-1.28%
1973	90.84	1.87%	85.66	2.65%	-0.79%
1974	87.85	-3.35%	82.54	-3.71%	0.37%
1975	88.04	0.21%	83.32	0.94%	-0.73%
1976	89.16	1.27%	86.44	3.68%	-2.41%
1977	88.97	-0.21%	87.80	1.57%	-1.78%
1978	88.88	-0.11%	88.98	1.32%	-1.43%
1979	87.85	-1.16%	88.59	-0.44%	-0.72%
1980	87.38	-0.53%	86.63	-2.23%	1.69%
1981	87.38	0.00%	86.73	0.11%	-0.11%
1982	86.54	-0.97%	84.10	-3.08%	2.12%
1983	85.42	-1.30%	86.44	2.75%	-4.05%
1984	88.32	3.34%	89.27	3.22%	0.11%
1985	88.22	-0.11%	90.15	0.98%	-1.08%
1986	88.50	0.32%	91.61	1.61%	-1.29%
1987	88.60	0.11%	91.90	0.32%	-0.21%
1988	92.06	3.83%	92.49	0.63%	3.19%
1989	92.43	0.41%	92.98	0.53%	-0.12%
1990	93.83	1.51%	93.17	0.21%	1.30%
1991	93.64	-0.20%	92.20	-1.05%	0.85%
1992	93.46	-0.20%	94.34	2.30%	-2.50%
1993	95.89	2.57%	94.73	0.41%	2.15%
1994	96.45	0.58%	95.80	1.13%	-0.54%
1995	98.69	2.30%	96.00	0.20%	2.10%
1996	99.91	1.22%	97.56	1.61%	-0.39%
1997	99.91	0.00%	98.73	1.19%	-1.19%
1998	100.00	0.09%	100.00	1.28%	-1.18%
Annual Averages					
1949-1972		3.94%		2.10%	1.83%
1973-1986		-0.05%		0.67%	-0.72%
1987-1998		1.02%		0.73%	0.29%

[1] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

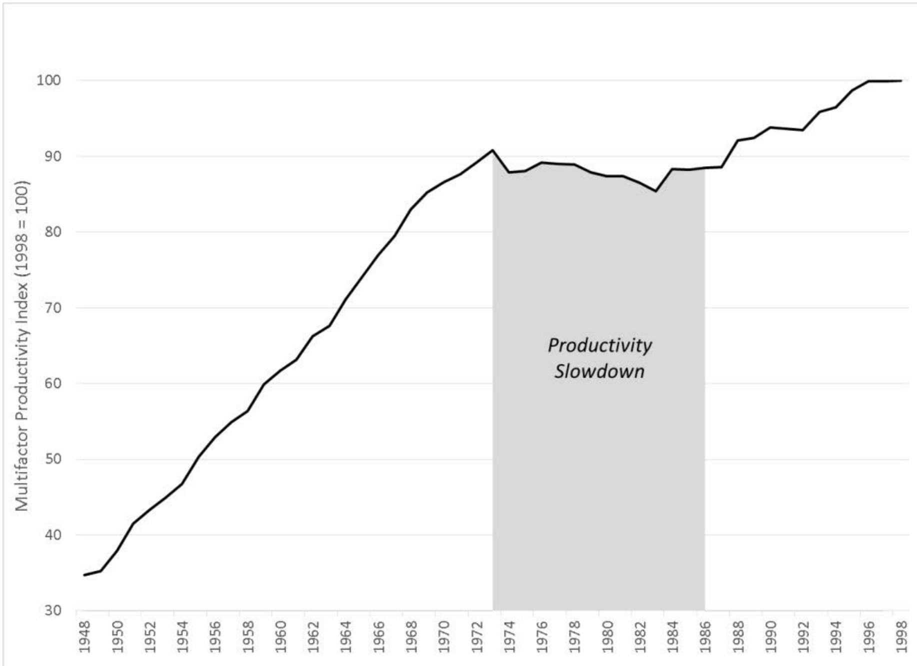

Figure 3. Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948–1998). MFP growth of U.S. utilities slowed during the period 1973 to 1986 under unfavorable business conditions.

The MFP growth of electric, gas and sanitary utilities fell to zero on average during the following years of markedly unfavorable business conditions, when rate cases were much more frequent. Both capital and labor productivity growth of this utility sector slowed markedly. MFP

growth of the U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[34]

The generation sector of the utility industry was a notable problem area during this period. Overbuilding generation capacity and cost overruns and delays on generation plant additions were widespread. Resultant overcapacity boosted sales in wholesale markets and widened the gap between wholesale and retail power prices. This gap was one of the factors that ultimately led to restructuring of retail power markets in many states.

MFP growth of utilities resumed at a slower 1.02 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP trends exceeded private business sector MFP trends by a modest 29 basis points on average.

The MRP Alternative

Advantages

A core advantage of MRPs is their potential to strengthen cost containment incentives.[35] The attrition relief mechanism can provide timely, predictable rate escalation that permits an extension of the period

[34] A basis point is one-hundredth of 1 percent.
[35] For further discussions of the rationale for MRPs see Lowry and Kaufmann (2002), Lowry and Woolf (2016), Comnes et al. (1995), and Kaufmann and Lowry (1995).

between rate cases. Escalation is based on cost forecasts, industry cost trends or both, rather than the utility's *specific* costs. Regulatory lag is thus achieved without sacrificing the timeliness of rate relief, increasing opportunities for a utility to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). A well-designed efficiency carryover mechanism can magnify the incentive "power" of the MRP.[36] Loosening the link between a utility's cost and its revenue gives it an operating environment more like that which producers in competitive markets experience.

MRPs can also encourage more operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency means that the prudence of management strategies must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). This potential advantage of MRPs in facilitating operating flexibility has been most thoroughly developed in the area of marketing flexibility (see Appendix A for further discussion).

PIMs play a special role in multiyear rate plans. The plans can strengthen incentives to contain costs.[37] These include costs incurred to maintain or improve service quality and worker safety. In competitive markets, a producer's revenue can fall abruptly if the quality of its offerings falls. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.[38]

Advantages of MRPs in encouraging utilities to consider cost-effective DSM and other distributed energy resources (DERs) are not widely recognized. MRPs can strengthen incentives to use DERs to contain load-related costs that are reflected in retail rates. The combination of an MRP, revenue decoupling, PIMs to encourage efficient DSM, and the tracking of DER-related costs can provide four "legs" for the DER "stool."[39] MRPs can reduce the need for complicated measurement of load and cost savings from DERs.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. Benefits of better performance can be shared with customers via earnings sharing mechanisms, plan termination provisions and careful ARM design. Customers can also benefit from more market-responsive rates and services. The strengthened performance incentives and reduced preoccupation with rate cases which MRPs provide can create a more performance-oriented corporate culture at utilities. This may increase the likelihood of success in mergers, acquisitions and unregulated market ventures in which utility companies engage.

MRPs also can increase the efficiency of regulation. Rate cases can be less frequent and better planned and executed. MRPs also facilitate scheduling rate cases so that proceedings overlap less. Streamlining ratemaking processes can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues, such as rules of prospective application. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively. Streamlined regulation has special appeal in situations where costs of regulation are especially high due to numerous utilities, large utilities or especially difficult regulatory issues. It is not surprising, then, that several commissions with unusually large regulatory burdens (e.g., Ontario and Germany) have been MRP leaders.

[36] See Sections 4 and 5 and Appendix A1 for further discussion of efficiency carryover mechanisms.
[37] See, for example, Comnes et al. (1995).
[38] Alberta Utilities Commission (2012), p. 186.
[39] A three-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in York and Kushler (2011).

Disadvantages

MRPs are complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. As we discuss at some length in Section 4, it can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR. Poorly designed plans can create opportunities for strategic behavior that reduces plan benefits for customers. For these and other reasons, most American jurisdictions have not yet adopted MRPs for gas and electric utilities. The concluding section of this report provides a more extensive discussion of reasons for the continued popularity of COSR.

3.2 How MRPs Can Help Address Contemporary Challenges

Benefits of MRPs tend to be greatest where traditional regulation is especially disadvantageous. These include situations where rate cases are especially frequent, a large number of utilities are regulated, marketing flexibility is especially desirable, and regulators have numerous other issues to attend to. We discuss here the extent to which these conditions are present today.

Need for Rate Cases and Expansive Cost Trackers

Table 1 shows that key business conditions that cause utility attrition are considerably less favorable today on balance than they were in the decades before 1973. Since the start of the Great Recession, sluggish economic growth and energy efficiency gains have caused unusually slow growth in average use of electricity by residential and commercial customers.[40] The financial stress on utilities of this development has been partly offset to date by unusually slow input price inflation.[41] However, inflation may be higher in the future due, for example, to rising bond yields. Increased penetration of DERs could further slow growth in average use.

The need for frequent rate cases varies among electric utilities. Variation in capex requirements is a major reason. In a period of sustained high capex, utilities need brisk escalation in rates, especially when the capex does not automatically produce new revenue. Some utilities need high capex today to replace aging distribution assets. This kind of capex does not, like distribution system extensions, typically produce new revenue without a rate case or cost tracker. Technological change has created opportunities for “smart grid” capex that improves utility performance but may not trigger much new revenue.[42]

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a UDC. Furthermore, slow demand growth and interest by some state regulatory commissions for VIEUs to rely on power purchase agreements rather than build and own more power plants is reducing the need for new VIEU generation capacity. On the other hand, some VIEUs are refurbishing or replacing old power plants.

[40] Demand growth in some states has also been affected by distributed generation and deindustrialization.
[41] Reduction in utility revenue due to declines in average electricity use can, in any event, be addressed by targeted remedies such as revenue decoupling.
[42] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

Technological Change

Technological change is creating new ways to meet the energy needs of customers. Well-designed MRPs can, by strengthening performance incentives and increasing operating flexibility, drive utilities to embrace these technologies where they are cost effective. However, when new technologies involve sizable up-front capex with little automatic revenue growth they can complicate MRP design.

Number of Utilities

The number of utilities that a state public utility commission regulates rarely grows, but sometimes falls due to mergers and acquisitions. Several states (e.g., California, New York, Pennsylvania and Texas) still regulate five or more electric utilities, and states must typically also regulate natural gas, telecommunications and water utilities.[43] Mergers and acquisitions have caused the number of utilities owned by some companies to rise over the years. Multi-utility companies have more incentive to adopt MRPs and other economical approaches to regulation.[44]

Marketing Flexibility

Marketing flexibility is increasingly useful to utilities in order to fashion time-sensitive rates, green power services, and miscellaneous new services enabled by new technologies. VIEUs may have greater need for marketing flexibility than UDCs. One reason is that the large-load customers whose demand has traditionally been most sensitive to the terms of service make a much larger contribution to a VIEU's base rate revenue. Another reason is that VIEUs may benefit more from renewable energy and electric vehicle options than UDCs since VIEUs may provide the power from company-owned generation. In addition, time-sensitive pricing can contain generation costs as well as transmission and distribution capacity needs.

Instability Concerns

We noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises questions about its ability to cope with increased penetration of customer-side distributed generation and storage. Penetration slows growth in average electricity use. To the extent that this leads to more frequent rate cases and more expansive cost trackers, utility performance deteriorates. Utilities may, for example, choose such a time for high replacement capex. The end result can be higher rates that further discourage use of grid services.[45] This is a source of potential instability in the utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut their costs.

[43] In contrast, regulation outside the United States is often conducted at the national level.
[44] Minneapolis-based Xcel Energy is an example of a multi-utility company that has publicly embraced MRPs. See Xcel Energy's "Strategic Plan for Growth," May 2015, http://investors.xcelenergy.com/Cache/1500071832.PDF?O=PDF&T=&Y=&D=&FID=1500071832&iid=4025308, and Xcel Energy's SEC Schedule 14A filed April 2015, http://investors.xcelenergy.com/Cache/28758163.PDF?O=PDF&T=&Y=&D=&FID=28758163&iid=4025308.
[45] For further discussion of the potential for a utility "death spiral," see Graffy and Kihm (2014).

Competing Needs for Regulatory Resources

Regulatory resources that are currently devoted to rate cases have many alternative uses in this era of rapid change. Among the areas where thoughtful review is currently needed are rate design, distribution system planning, and the terms of compensation for customer-side DER services.

Difficulty of MRP Implementation

The difficulty of implementing MRPs changes over time and varies considerably among utilities. One key challenge is the identification of a reasonable ARM. Implementation of index-based ARMs has traditionally been easier for UDCs than for vertically integrated utilities. The cost of UDC base rate inputs tends to grow gradually and predictably as the economies UDCs serve gradually expand. In contrast, VIEUs have in the past had "stair step" cost trajectories with large rate increases when large power plants came into service alternating with periods of slow cost growth as new units depreciated. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays.

However, many UDCs have in recent years proposed accelerated grid modernization programs involving several years of high capex. The need for these programs is often difficult for regulators to judge in an era of rapid technological change and shifting demand. VIEUs, meanwhile, are experiencing *more gradual* cost growth because fewer generation capacity additions are needed and capacity that is built tends to be more modular natural gas-fired or wind-powered units. Depreciation of older generation plant meanwhile slows rate base growth.[46] Figures 4 and 5 illustrate the changing needs for rate escalation for UDCs and VIEUs.

Consider also that jurisdictions vary in their regulatory traditions and human capital (the experience and the expertise of regulatory practitioners). Generally speaking, adoption of MRPs is easier for jurisdictions that have experience with the use of forward test years in rate cases. Accumulation of experience with MRPs in the United States and improvements in MRP design will facilitate broader implementation.

Conclusions

Our analysis suggests that unusually slow inflation since the Great Recession of 2008 has thus far offset declining residential and commercial average use to contain the need for electric utilities to file frequent rate cases. However, these business conditions are still less favorable on balance than they were before 1972 when COSR worked well and became a tradition. Resumption of normal inflation and accelerated penetration of customer-side DERs may well occur and would spark more interest in MRPs. MRPs can also address the need for marketing flexibility.

Whereas the need for multiyear rate plans may be greater for UDCs with high capex, the ease of implementing these plans is often greater for VIEUs today. VIEUs also may have stronger interest in marketing flexibility. This helps to explain why use of MRPs is growing most rapidly in the United States for VIEUs.

[46] However, some utilities are building new, cleaner generating facilities (including emissions control equipment) or modernizing older generation plants. Aging generating capacity (especially nuclear capacity) can have rising operating costs.

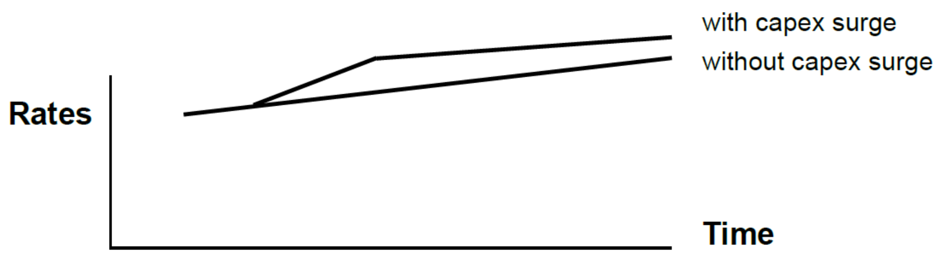

Figure 4. Rate Escalation Requirements for UDCs. Capex surges can accelerate the normally gradual escalation of UDC rates.

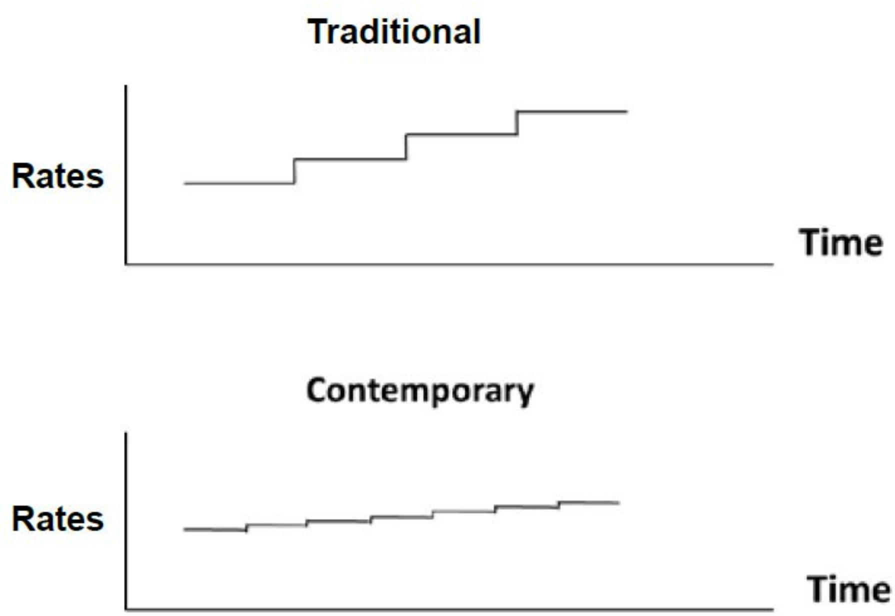

Figure 5. Rate Escalation Requirements for VIEUs. Rate escalation requirements of VIEUs are becoming more gradual.

Growing familiarity with best practices in the design of plans for UDCs may encourage greater use in this utility sector. Use of MRPs for UDCs may also increase as they complete accelerated grid modernization programs that complicate plan design and return to gradual cost growth. Companies and commissions with unusually large regulatory burdens gain special advantages from streamlined regulation. Some of these companies and commissions are likely to be MRP leaders.

4.0 MRP Design Issues

This section takes a deeper look at important issues in MRP design. We first consider how attrition relief mechanisms (ARMs) can cap rate and revenue growth and then discuss major approaches to ARM design. Following are discussions of cost trackers, decoupling, performance metric systems and efficiency carryover mechanisms.

4.1 Attrition Relief Mechanisms

Rate Caps vs. Revenue Caps

ARMs can escalate allowed rates or revenue. Limits on rate growth are sometimes called *price caps.*[47] In price cap plans, allowed rate escalation is often applied separately to multiple service "baskets." For example, there might be separate baskets for small-load (e.g., residential and general service) and large-load customers. The utility can typically raise rates for services in each basket by a common percentage that is determined by the ARM, cost trackers and any earnings sharing adjustments.[48] Customers in each basket are insulated from the discounts and demand shifts going on with services in other baskets, except as these developments influence shared earnings or cost trackers.

Price caps have been widely used to regulate utilities, such as telecommunications carriers, which are encouraged to promote use of their systems. In the electric utility industry, legacy rate designs feature usage charges that are well above the utility's short-run marginal cost of service provision.[49] With less frequent rate cases, price caps can therefore make utility earnings more sensitive to the kWh and kW of system use, strengthening utility incentives to encourage greater use.

Under revenue caps, the focus is on limiting growth in allowed revenue (the revenue requirement).[50] Services may still be grouped in baskets. Revenue caps are often paired with a revenue decoupling mechanism that relaxes the link between revenue and system use.

Methods for ARM Escalation

Several well-established approaches to ARM design can, with sensible modifications, be used to escalate rate or revenue caps. We use revenue cap examples in the following discussion.

<u>Indexing</u>

An indexed ARM is developed using index and other statistical research on utility cost trends. For example, a revenue cap index for a power distributor might take the following form:

$$growth\ Revenue = Inflation - X + growth\ Customers + Y + Z \qquad [2]$$

The inflation measure in such a formula is often a macroeconomic price index such as the Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes

[47] A notable early discussion of price caps for electric utilities is Lowry and Kaufmann (1994).
[48] In some plans, slower growth in rates for some services in a basket can, within limits, permit more rapid rate growth for other services in the same basket.
[49] Marginal cost is the additional cost incurred to provide a small increment of service.
[50] The allowed revenue yielded by a revenue cap escalator must be converted into rates, requiring assumptions for billing determinants.

used in ARM design. X, the productivity or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer distributors. A stretch factor (sometimes called *consumer dividend*) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives that are expected under the plan.

Index-based ARMs compensate utilities automatically for important external cost drivers such as inflation and customer growth. This provides timely rate relief that reduces attrition and operating risk without weakening performance incentives. Between rate cases, customers can be guaranteed benefits of productivity growth which equals (or, with a stretch factor exceeds) industry norms. Controversies over cost forecasts can be avoided.

On the other hand, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging and overcompensate them on other occasions, such as the years following a surge. Capex surges can be addressed by cost trackers, but trackers involve their own complications, as we discuss further below. Design of indexed ARMs applicable to capital cost sometimes involve statistical cost research that is complex and sometimes controversial.[51] Consultants will seek entry to the field by advocating unusual values for X which serve the interests of their clients. However, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).

Forecasts

A forecasted ARM is based on multiyear cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019 and 3 percent in 2020). The outcome is much like that of a rate case with multiple forward test years.

Familiar accounting methods can be used to forecast growth in capital cost. The trend in the cost of older capital is relatively straightforward to forecast since it depends chiefly on mechanistic depreciation.[52] The more controversial issue is the value of plant additions during the plan.

Shortcuts are sometimes taken in preparing forecasts for ARM design. For example, forecasted plant additions may be set for each plan year at the utility's average value in recent years [53] or at its value for the test year of the most recent rate case. Operation and maintenance (O&M) expenses are sometimes forecasted using index-based formulas similar to equation [2].

One important advantage of forecasted ARMs is their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Some forecasted ARMs make no adjustment to rates during the plan if the actual cost incurred differs from the forecast. This approach to ARM design can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

On the downside, forecasted ARMs do not protect utilities from unforeseen changes in inflation and operating scale.[54] The biggest problem with forecasted ARMs, however, is that it can be difficult to establish just and reasonable multiyear cost forecasts. It is often difficult to ascertain the value to

[51] For example, productivity studies filed in proceedings to establish an MRP often use mathematically stylized representations of capital costs which differ from those used in traditional ratemaking. Witnesses have disagreed on the appropriate capital cost treatment and sample period for a productivity study.
[52] Note, however, that salvage value and decommissioning costs are sometimes controversial.
[53] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[54] Operating scale risk can be reduced by forecasting unit costs (e.g., cost per customer) and then truing up for actual scale growth.

customers in a given cost forecast. Resources that the regulatory community may expend on benchmarking and engineering studies to develop competent independent views of needed utility cost growth can be sizable.

Hybrids

"Hybrid" approaches to ARM design use a mix of indexing and other escalation methodologies.[55] The most popular hybrid approach in the United States involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs. Indexes address O&M expenses while forecasts address capital costs.

Indexation of O&M revenue provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. Good data on O&M input price trends of electric (and gas) utilities are available in the United States. The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the other hand, capex forecasts are required and can be controversial.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends entirely on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but have occasionally applied to rates for energy procurement. An analogous concept for a plan with revenue decoupling is the revenue/
customer freeze, which permits revenue to grow at the (typically gradual) pace of customer growth.

4.2 Cost Trackers

Basic Idea

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Costs are then recovered by tariff sheet provisions called *riders.*

A cost tracker helps a utility's revenue track its own costs more closely. While this is contrary to the spirit of PBR — which focuses on strengthening incentives — it can make it easier for a utility to operate under an MRP, which has an ARM for other costs of base rate inputs. Where cost containment incentives generated by trackers are a concern, methods are available to address them. For example, tracked costs can be subject to especially intensive prudence review.[56] Tracker mechanisms can be incentivized, as we discuss further below.

Capital Cost Trackers

Capital cost trackers compensate utilities for annual costs (e.g., depreciation, return on asset value, and taxes) that capex (or plant additions) give rise to. Such trackers are sometimes used in MRPs to address capex surges that are difficult to address with an ARM. Capex surges are sometimes needed — for

[55] A "hybrid" designation can in principle be applied to a number of ARM design methods, including the design used in Great Britain. However, it would not apply to regulatory systems, such as those used in Vermont, which index O&M revenue but use cost of service regulation for capital cost.
[56] The reduction in rate cases that MRPs make possible frees up resources to review these costs.

example, when VIEUs make large additions to generating capacity, replace large components of existing generating plants, or add extensive emission control systems. VIEUs and UDCs alike may need high capex for rapid build-out of AMI or other smart grid technologies, to meet increased safety and reliability standards, and to replace facilities built in earlier periods of rapid system growth.

Forecasted and hybrid ARMs can address expected capex surges better than index-based ARMs. Thus, capital cost trackers are more commonly combined with index-based ARMs. However, MRPs with forecasted or hybrid ARMs sometimes permit utilities to request supplemental revenue for unforeseen capex, or for capex with uncertain completion dates.[57]

Ratemaking Treatments of Tracked Costs

Supplemental revenue that capital cost trackers produce is often based on capex forecasts. Treatment of variances from approved budgets then becomes an issue. Some capital cost trackers return all capex underspends to ratepayers promptly. As for overspends, some trackers permit conventional prudence review treatment. In other cases, no adjustments are subsequently made between rate cases if capex exceeds budgets. Mechanisms also have been approved in which deviations from budgeted amounts that are in prescribed ranges are shared formulaically (e.g., 50-50) between the utility and its customers.

Appraising the Need for Trackers

A key question in approvals of capital cost trackers is the need for tracking. This question involves two issues: the need for high capex and the need for tracking the capex. It can be challenging to ascertain the need for high capex. For example, trackers for energy distributors sometimes address costs of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges, such as those for new generation capacity or emissions control facilities.[58] Accelerated distribution modernization plans involve many decisions about emerging technology and consumer expectations, as well as timing and scale issues, and regulators in some jurisdictions may not have much expertise in evaluating them.

Determining the need for a capital cost tracker is complicated for a utility operating under an ARM that provides some compensation for capex. An indexed ARM, for example, escalates revenue associated with an older plant between rate cases even though the cost of that plant tends to decline due to depreciation. Furthermore, the X factor in the escalator reflects productivity growth by peer group utilities which has been slowed by capex.[59] If the utility is given dollar-for-dollar compensation for substandard productivity growth when normal kinds of capex surge, but the X factor in the revenue cap formula reflects only the industry productivity trend when capex does not surge, customers are not ensured the benefit of the industry productivity trend in the long run, even if it is achievable.

Ratemaking Treatment of Other Costs

Another issue that arises when considering a capital cost tracker is the ratemaking treatment of costs not included in the tracker. Separate recovery of certain capex costs means that the cost of residual capital —

[57] For example, trackers have been used in conjunction with hybrid or forecasted ARMs to address costs of new generating facilities, major generator refurbishments and AMI.

[58] Generation plant additions also require discretion, but regulators of VIEUs have years of experience considering both the need for new capacity and the types of generation technology. Many states require integrated resource planning or a certificate of public convenience and necessity, or both, before additions to generation capacity can proceed. In addition, there are often competitive alternatives to a utility’s proposal to increase capacity. Proponents of these alternatives press their cases in these hearings.

[59] Capex often slows growth in multifactor productivity, even while accelerating O&M productivity.

consisting mainly of gradually depreciating older plant — tends to rise more slowly and predictably. If *all* capex cost flows through trackers, the residual capital cost is that of older plants and may *decline* due to depreciation. Additionally, productivity growth of electric O&M inputs may be brisk. For these reasons, expansive capex trackers often coincide with freezes on rates addressing costs of other inputs.[60] This "tracker/freeze" approach to MRP design has recently been used by VIEUs in Arizona, Colorado, Florida, Louisiana and Virginia.[61]

Capital Cost Tracker Precedents

There are numerous precedents for capital cost trackers in the regulation of retail rates for U.S. gas, electric and water utilities.[62] The popularity of such trackers reflects in part the generally traditional approach to regulation in U.S. jurisdictions. Most capital cost trackers in the United States are not embedded in MRPs with ARMs that provide automatic rate escalation for cost pressures. The alternative to these trackers for regulators is thus more frequent rate cases that require review of costs of *all* base rate inputs and weaken utilities' incentives to contain them. Note also that many trackers are approved in jurisdictions that do not have fully forecasted test years.

Capital cost trackers have been components of a number of MRPs. Plans in California and Maine, for example, have had trackers for costs of AMI.[63] Plans in Alberta and Ontario have permitted cost trackers for a broader range of distributor capex.[64]

Capital cost trackers are occasionally incentivized. In California, for example, the AMI cost trackers of Southern California Edison and San Diego Gas & Electric have involved preapproved multiyear cost forecasts. Each company has been permitted to recover 100 percent of its forecasted cost up to a cap without further prudence review. Above the cap, each company can recover 90 percent of incremental overspends in a certain range without a prudence review. Beyond this range, recovery of incremental overspends requires a prudence review. San Diego Gas & Electric was permitted to keep 10 percent of its underspends.

[60] In an MRP with a revenue cap, the analogous ratemaking treatment is a revenue per customer freeze.
[61] See, for example, Arizona Corporation Commission (2012), Colorado Public Utilities Commission (2015), Florida Public Service Commission (2013), Louisiana Public Service Commission (2014), and Virginia Acts of Assembly (2015).
[62] Lowry et al. (2015).
[63] California Public Utilities Commission (2007a), California Public Utilities Commission (2008b), and Maine Public Utilities Commission (2008).
[64] See Alberta Utilities Commission (2012), for a discussion of capital cost trackers in Alberta distribution regulation and Section 6.7 of this report for a discussion of capital cost trackers in Ontario power distribution regulation.

Decoupling Under an MRP

Revenue decoupling can improve utility incentives to adopt a wide array of initiatives to encourage cost-effective DSM and other DERs.[65] In addition to eliminating the utility's short-term incentive to increase retail sales, decoupling can reduce the utility's risk in using retail rate designs that encourage efficient DERs. For example, decoupling reduces risks of revenue loss when customers are offered time-sensitive usage charges that shift loads away from peak demand periods.

When average use is declining for any reason, decoupling reduces the needed frequency of rate cases. Decoupling also reduces controversy over billing determinants in rate cases with future test years because prices will adjust — up or down — based on actual utility sales.

A recent power industry survey found revenue decoupling in use in 14 jurisdictions.[66] DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is used in tandem with MRPs in California, Minnesota and New York.

Decoupling is much more widely used by gas distributors. This reflects the fact that gas distributors have often experienced declining average use, due chiefly to external forces such as the improved efficiency of furnace technologies. Some utilities have decoupling for some services and lost revenue adjustment mechanisms (LRAMs) for others.[67]

4.3 Performance Metric Systems

Metrics (sometimes called *outputs*) quantify utility activities that matter to customers and the public.[68] These metrics can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce costs of oversight. Target ("benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. A performance incentive mechanism links utility revenue to the outcome of one or more performance appraisals. "Scorecards" summarizing performance metric results are sometimes tabulated. These may be posted on a publicly available website or included in customer mailings.

Service Quality PIMs

Service quality PIMs are used in multiyear rate plans to improve the incentive balance between cost and quality. This can simulate connections between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have addressed both reliability and customer service.[69]

Reliability metrics have addressed systemwide reliability, reliability in subregions, and the success of restoration efforts after major storms. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics are the system average interruption duration index

[65] For further discussion of revenue decoupling, see Lazar et al. (2016).
[66] Lowry, Makos and Waschbusch (2015).
[67] Electric utilities with decoupling for most customers and LRAMs for some large-volume customers include Portland General Electric, Duke Energy Ohio and AEP Ohio.
[68] Whited et al. (2015).
[69] For a survey of reliability PIMs, see Kaufmann et al. (2010). For a survey of customer service PIMs, see Kaufmann (2007).

(SAIDI) and system average interruption frequency index (SAIFI).[70] Customer service PIMs have addressed customer satisfaction, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on service quality metrics is usually assessed through a comparison of a company's current year performance to its recent historical performance. Because of limited availability and lack of standardization of service quality data, benchmarking a company's performance on service quality using data from other utilities is difficult.

Demand-Side Management PIMs

Demand-side management PIMs link utility revenue to reward (or penalize) utilities for their performance on DSM initiatives. Metrics on load savings are often used in these PIMs. Compensation for load savings can take several forms:

- *Shared savings.* This approach grants the utility a share of the estimated net benefits that result from DSM. It can therefore encourage utilities to choose more cost-effective programs and manage them more efficiently. However, estimation of net benefits can be complex and controversial. *Ex post* and *ex ante* appraisals of net benefits (or a mix of the two) may be used in net benefit calculations.

- *Management fees.* This alternative grants the utility an incentive equal to a share of program expenditures. The incentive calculation depends on costs incurred (specifically, expenditures by the utility) but not on benefits achieved. Thus, the utility is rewarded for spending money, which is not necessarily well correlated to desired policy outcomes. However, the simplicity of management fees makes them an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), and its ease of administration has encouraged its use for other DSM programs as well.

- *Amortization.* DSM expenditures can be amortized so that the utility earns a return on them like capital expenditures. Premiums are sometimes added to the rate of return on equity (ROE) for these expenditures, and these premiums may be contingent on achieving certain DSM performance goals.

Most DSM PIMs require estimates of load savings. These savings can be estimated using engineering models, typical savings documented in technical reference manuals (deemed savings), or statistical analyses of customer billing data. Even with high-quality data, reliably estimating savings can be challenging. The complications include free riders (customers who would have implemented the efficiency measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient and thus less costly to operate).

DSM initiatives vary with respect to the difficulty of measuring load savings and the scale of expenditures that can produce material management fees and amortization. Some DSM PIMs encourage utilities to design programs with more measurable impacts or larger expenditure requirements. Other DSM initiatives that are equally or more cost-effective may be neglected. Such initiatives may include changes

[70] Other reliability metrics include the customer average interruption duration index (CAIDI) and the momentary average interruption duration index (MAIFI).

in default retail rate designs, cooperation with third-party vendors of energy services and products, support for upgraded state appliance efficiency standards and building codes, and other efforts to transform energy service markets.

Pros and Cons of Demand-Side Management PIMs

Demand-side management PIMs can be a useful addition to multiyear rate plans. Under these plans, utilities may still lack sufficiently strong incentives to encourage DSM. For example, most MRPs accord tracker treatment to fuel and purchased power expenses. Transmission costs may also be tracked. MRPs may provide some incentive to contain load-related capex, but not to levels found in unregulated markets.

Performance incentive mechanisms for DSM can strengthen utility incentives to use DSM as a cost management tool. Such PIMs also can address the utility's short-term throughput incentive in an MRP that does not include revenue decoupling or an LRAM. Well-designed demand-side management PIMs can encourage more cost-effective DSM programs.

Still, demand-side management PIMs have drawbacks. For example, they can involve complex calculations that may complicate regulatory proceedings. Shared savings PIMs are particularly complex. By motivating utilities to improve their performance in relation to specific programs, PIMs may lead to a deterioration in other aspects of DSM performance that are not measured.[71] In addition, utility rewards for load savings can sometimes become sizable over the years.

Precedents for Demand-Side Management PIMs

A 2014 survey by the Edison Foundation Institute for Electric Innovation found that DSM PIMs are quite common in the United States.[72] In all, 29 states had some form of DSM PIM. Among them, all but five had also adopted decoupling or LRAMs. Demand-side management PIMs were included in more than half of the U.S. electric MRPs identified. Among DSM PIMs, those focused on conservation and energy efficiency programs were the most common, and some states have decades of experience with them. PIMs also may address peak load management.

Despite their relative complexity, shared savings mechanisms have been the most popular PIM compensation approach for many years. However, management fees are also widely used. In some cases, regulators have approved more than one compensation approach (e.g., shared savings for programs with quantifiable benefits; management fees for education and marketing programs).

Most DSM PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, such as those where substantial transmission and distribution capex will be needed in the near future to replace aging assets or accommodate growing load. We discuss some examples of these programs in Section 6.

4.4 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms limit true-ups of a utility's revenue to its cost when an MRP concludes. These mechanisms encourage utilities to achieve long-term performance gains that can benefit customers after a plan's conclusion. They can also counteract some adverse incentives that can result under MRPs from periodic rate cases that set a utility's revenue requirement equal to its cost. Due to compression of

[71] New York and other jurisdictions are for this reason considering less program-specific DSM performance metrics like normalized volume per customer.
[72] Institute for Electric Innovation (2014).

the period during which benefits of long-term performance gains improve their bottom line, utilities may have less incentive in later years of a plan to limit upfront costs needed to achieve such gains. In addition, rate cases provide disincentives to contain costs that influence the revenue requirement in the first year of the next plan. For example, there may be less incentive to strike hard bargains with vendors. Given the different incentives to contain cost in early and later plan years, utilities may also be incentivized to defer certain expenditures in the early years of the plan so that these expenses show higher totals in the MRP test year. Customers may then “pay twice” for some costs that are funded by the ARM.

To counteract such incentives, efficiency carryover mechanisms can be designed that reward utilities for offering customers good value in later plans. Such mechanisms can also penalize utilities for offering customers poor value. One kind of efficiency carryover mechanism involves a comparison of revenue requirements in the test year of the next rate case to a benchmark. The mechanism may take the form of a targeted PIM. The revenue requirement in a forward test year could, for example, correspond to the following formula:

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot (Benchmark_{j,t+1} - Cost_{j,t+1})$$

where α is a share of the value implied by benchmarking and takes a value between 0 and 1.[73] Variance between benchmark and actual costs can, alternatively, be used to adjust the X factor in the next plan if it has an index-based ARM.

Choice of a benchmark is an important consideration in design of this kind of efficiency carryover mechanism. One approach is to use as the benchmark the revenue requirement established by the expiring MRP (extended by one year in the case of a forward test year). Cost (or the proposed revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research which is completely independent of the utility’s cost.

[73] Note that the formula allows for the possibility that only a subset (j) of the total cost is benchmarked. This could be the subset that is easier to benchmark.

Efficiency Carryover Mechanisms: An Example From New England

National Grid, a company with utilities that have long operated under MRPs in Britain, incorporated efficiency carryover mechanisms in plans for several power distributors in the northeast United States. For example, in Massachusetts, New England Electric System and Eastern Utilities Associates were in the process of merging when they were acquired by National Grid. In 2000 the Massachusetts Department of Telecommunications and Energy approved a settlement which, among other things, detailed an MRP under which the surviving power distributors of the merging companies (Massachusetts Electric and Nantucket Electric) would operate for 10 years.[74]

The settlement did not require rates to be reset in a rate case at the conclusion of the rate plan. However, the settlement limited over a 10-year "Earned Savings Period" the extent to which rates established in future rate cases could reflect the benefits of cost savings achieved during the plan. These "earned savings" were to conform to the following formula:

Earned Savings = Distribution revenue under rates applicable in March 2009

- *pro forma cost of service (COS)*

The focus on 2009 reflects the fact that Massachusetts has historical test years, so this was expected to be the first year in which cost could provide the basis for post-plan rates. During the Earned Savings Period, Massachusetts Electric was permitted to add to its cost of service during any rate case the lesser of $66 million and 100 percent of earned savings achieved in 2009 up to $43 million, plus 50 percent of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. Any earned savings would be capped at $66 million.

At the end of the plan period, National Grid requested a large revenue requirement increase. This was explained in part by the need to replace aging infrastructure. The utility did not include an allowance for earned savings in its 2009 rate request.

Regulators in Australia, Britain and Ontario routinely take an approach to cost benchmarking which uses econometric methods in rate setting. In the United States, econometric benchmarking studies have occasionally been filed by U.S. utilities. Public Service of Colorado, for example, has filed econometric benchmarking studies of its forward test year revenue requirement proposals for the cost of its gas and electric operations.[75] We discuss econometric benchmarking further in Appendix B.3.

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP provisions. Australia has been a leader, using these mechanisms in both power transmission and distribution regulation. The Alberta Utilities Commission uses efficiency carryover mechanisms in MRPs for provincial energy distributors.

[74] See Settling Parties in Massachusetts (1999).
[75] Lowry, Hovde, Kalfayan, Fourakis, and Makos (2014).
Lowry, Hovde, Getachew, and Makos (2010).
Lowry, Hovde, Getachew, and Makos (2009).

4.5 Menus of MRP Provisions

Some MRPs contain menus of provisions from which utilities can choose. Menus typically include a key ARM provision and another plan provision affecting utility finances. In a plan with an indexed ARM, a utility might, for example, have a choice between (1) a low X factor and an earnings sharing mechanism and (2) a higher X factor and no earnings sharing.

An "incentive compatible" menu incentivizes a utility to reveal, by its choice between menu options, its potential for containing cost growth. This approach to MRP design has been discussed in the academic regulatory economics literature since the 1980s. Major theoretical contributions have been made by Michael Crew, Paul Kleindorfer and Nobel prize-winning economist Jean Tirole.[76]

The Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interstate access services of large local telecommunications exchange carriers.[77] The menu embedded in the Information Quality Incentive of British regulators is explained in Appendix A.4.

[76] Laffont and Tirole (1993), Crew and Kleindorfer (1987), Crew and Kleindorfer (1992), and Crew and Kleindorfer (1996).
[77] Federal Communications Commission (1990).

5.0 Incentive Power Research

Pacific Economics Group has developed an Incentive Power model to explore the incentive impact of alternative regulatory systems such as multiyear rate plans. The model addresses the situation of a hypothetical energy distributor that has several kinds of initiatives available to improve its cost performance. Using numerical analysis, the model can predict the cost savings that will occur under various regulatory systems. The regulatory systems considered are stylized but resemble real-world options in use today. Appendix B.1 provides details of the research.

Key results of our incentive power research include the following:

- *Cost containment incentives depend on the frequency of rate cases.* Today, utilities in the United States typically hold rate cases every three years.[78] For a utility with normal operating efficiency, our model finds that long-run cost performance on average improves 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years. This means that cost will be about 5 percent lower after 10 years under the MRP. For a utility with an annual revenue requirement of $1 billion, this would be an annual cost saving of $50 million in real terms.

- *If rate cases under traditional regulation occur more frequently, the incremental incentive impact of an MRP is higher.* For example, the long-run impact of MRPs with five-year terms is 0.75 percent additional annual cost containment if rate cases would otherwise be held every two (rather than three) years. This kind of comparison is more relevant to regulators when the alternative to an MRP is frequent rate cases or extensive use of cost trackers.

- *Earnings sharing mechanisms weaken incentives produced by an MRP.* For example, MRPs with a five-year term and 75/25 sharing of all earnings variances between utilities and their customers produce only 0.27 (rather than 0.51) percent annual performance gains compared to a three-year rate case cycle.

- *Performance gains from more incentivized regulatory systems are greater (smaller) for companies with a low (high) initial level of operating efficiency.*

- *Incentives generated by an MRP can be materially strengthened by a well-designed efficiency carryover mechanism or system of menu options.* Suppose, for example, that when rates are rebased the utility absorbs 10 percent of the variance between its own cost and a statistical benchmark of cost. Our model finds that annual performance gains increase by 90 basis points in a plan with a five-year term relative to those from traditional regulation with a three-year rate case cycle. This means a 9 percent lower cost after 10 years.

Our incentive power research has a number of implications. It shows that a utility's performance incentives and performance can be materially affected by the regulatory system under which it operates. This means that more incentivized regulatory systems such as well-designed MRPs can provide material cost savings that can be shared between utilities and their customers. New MRP design provisions such as efficiency carryover mechanisms and menu options can materially increase incentive power.

[78] Lowry and Hovde (2016), p. 44.

Utility performance is materially affected by the frequency of rate cases, and the frequency of rate cases is affected by the adversity of business conditions. Our incentive power research thus supports the notion that performance of utilities under COSR tends to decline under adverse business conditions. When business conditions are adverse, regulators should be especially vigilant about utility operating prudence and consider how to strengthen performance incentives. That can be particularly important given that utilities typically advocate for expedited recovery of their costs when business conditions are adverse, and often are successful.

6.0 Case Studies

This section presents case studies of multiyear rate plans. Each case study discusses the nature of MRPs enacted, identifying important provisions and controversies and rationales for utility regulators to choose PBR. We also consider effects of PBR on cost performance using power distributor productivity indexes. These indexes consider productivity in the provision of customer services such as billing and distribution services. We compare productivity trends of utilities operating under rate plans, or less formal rate case stayouts, to contemporaneous utility norms. Appendix B.2 provides details of our utility productivity research.

6.1 Central Maine Power

The Maine Public Utilities Commission was for many years a leader in energy utility PBR.[79] Central Maine Power (CMP) is Maine's largest electric utility. From 1995 to 2013, it operated under a succession of three MRPs called *alternative rate plans.* Full rate cases did not occur between plans. The first plan took place while the company was still vertically integrated, while later plans applied to CMP's distributor services after restructuring. All three plans were outcomes of settlements between CMP and other parties.

In a 1993 rate case decision, the Commission encouraged CMP to operate under an alternative rate plan. This decision took into consideration CMP's recent history of rapid rate escalation and losses of margins from large-volume customers. The Commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[80] The Commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[81]

The Commission outlined its views of potential costs and benefits of MRPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial

[79] Thomas Welch, a former telecommunications lawyer, chaired the Commission during these years.
[80] Maine Public Utilities Commission (1993), pp. 14–15.
[81] Maine Public Utilities Commission (1993), p. 126.

> perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[82]

The decision discussed the marketing flexibility benefits of MRPs at some length:

> Price caps coupled with pricing flexibility allow a regulated firm to compete on a more equal basis with other suppliers that threaten its markets: a firm is given wide pricing discretion and the opportunity to offer new services in the absence of case-by-case regulatory approval.
>
> An important benefit of price caps lies with protecting the so-called "core customers" from competition encountered in other markets. For example, if separate price caps are placed on each class of customer, whatever revenues the utility earns in the more competitive industrial markets would not directly affect the price it can charge (say) residential customers… In contrast, under [COSR] a firm is generally given the opportunity to receive revenues corresponding to its revenue requirement. This implies that whenever the firm receives fewer revenues from one group of customers, it would have the right to petition for increased revenues from others by proposing to raise their prices….[83]

Plan Designs

Attrition Relief Mechanism

All three of CMP's plans featured price caps with index-based escalators. The caps applied to both base and energy rates for vertically integrated service in the first plan, and to base rates for distributor services in later plans. Evidence on input price and productivity trends of Northeastern U.S. electric utilities was presented and debated in each proceeding to inform the choice of an X factor.[84] Macroeconomic price indexes were used as inflation measures. The accuracy of such measures as proxies for utility input price inflation was a prominent issue in one proceeding.

Marketing Flexibility

When CMP was vertically integrated, it had a special need for flexibility in its marketing to pulp and paper customers, some of whom had cogeneration options or were economically marginal, or both. Maine's legislature passed a law allowing the Commission to authorize pricing flexibility plans which permit utilities to discount their rates with limited or no Commission approval. The Commission also encouraged utilities to develop special contracts with customers.

The Commission noted the following in approving the first alternative rate plan for CMP:

Because CMP will have substantial exposure to revenue losses due to discounting, the Company will have a strong incentive to avoid giving unnecessary discounts, and it will have a strong incentive to find cost savings to offset any such losses. Pricing flexibility gives CMP the opportunity to use price to compete to retain customers.[85]

[82] Maine Public Utilities Commission (1993), p. 130.
[83] Maine Public Utilities Commission (1993), p. 130.
[84] X factors in Maine were commonly referred to as "productivity offsets."
[85] Maine Public Utilities Commission (1995), p. 19.

Marketing flexibility provisions in this plan included these features:

- For core customers, CMP was free to set rates between the rate cap and a rate floor based on an estimate of long-term marginal cost.
- CMP could receive expedited approval of new targeted services.
- CMP could also receive expedited approval of special rate contracts with individual customers. Different provisions applied for short-term and long-term contracts.
- Revenue lost during a plan as a result of discounts was recoverable from other customers only through the earnings sharing mechanism (ESM). In the first plan, a cap of 15 percent was placed on overall lost revenues that could be recovered through the ESM.

Subsequent plans did not make substantial changes to these pricing flexibility provisions.

Other Plan Provisions

Earnings sharing mechanisms and penalty-only service quality PIMs were included in all three plans. Service quality benchmarks for these PIMs became more demanding over time.

The first-generation plan also featured a tracker for DSM costs and a DSM PIM. These latter features were subsequently removed with restructuring and establishment of a third-party DSM program administrator in Maine.

Outcomes

Cost Performance

Table 4 and Figure 6 compare the trends in O&M, capital and multifactor productivity of the company's power distributor services to the average for U.S. electric utilities in our sample from 1980 to 2014. The table shows that from 1980 to 1995, before MRP regulation, the company's MFP growth was a little slower than that of the full sample on average. Over the 1996 to 2013 period during which CMP operated under alternative rate plans, it averaged 0.92 percent annual MFP growth, while the full sample of U.S. electric utilities averaged 0.42 percent annual MFP growth. The MFP growth differential thus averaged 50 basis points. Table 4 also shows that CMP accomplished this through much more rapid *capital* productivity growth. This is notable given the interest of many regulators today with capex containment. O&M productivity trends of CMP and the sample were more similar.

Nuclear Problems

At the start of PBR, when CMP was still vertically integrated, it owned 38 percent of Maine Yankee Atomic Power Co., owner and operator of a nuclear generating station. CMP relied on this station for a sizable share of its power supply. The station experienced an extended outage during the plan. The plan did not fully compensate CMP for the increased costs for repairs, decommissioning and purchased power expenses that resulted from the Maine Yankee outage. This resulted in lower earnings for CMP, which in 1998 triggered the lower bound of the ESM.

Table 4. How Productivity Growth of Central Maine Power Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	CMP			U.S. Average		
	MFP	PFP O&M	PFP Capital	MFP	PFP O&M	PFP Capital
1980	-0.17%	-2.17%	1.08%	-0.49%	-4.19%	1.24%
1981	0.45%	-3.00%	1.47%	0.17%	-2.42%	1.25%
1982	0.08%	-1.43%	1.84%	0.87%	-1.20%	1.53%
1983	0.42%	-2.22%	1.82%	0.51%	-0.38%	0.98%
1984	1.63%	1.28%	1.80%	1.27%	-0.22%	1.79%
1985	0.75%	-1.94%	1.94%	0.95%	-0.21%	1.37%
1986	2.08%	0.89%	2.57%	0.91%	0.88%	0.97%
1987	0.59%	-1.10%	1.28%	0.44%	-0.12%	0.68%
1988	-0.49%	-1.43%	-0.03%	0.57%	1.55%	0.24%
1989	-0.83%	-0.12%	-1.25%	0.26%	0.00%	0.23%
1990	-0.97%	0.24%	-1.79%	0.18%	0.64%	-0.05%
1991	-0.43%	1.04%	-1.39%	-0.03%	0.58%	-0.32%
1992	1.32%	2.51%	0.64%	0.48%	1.61%	0.10%
1993	-0.24%	-2.55%	1.04%	0.45%	1.19%	0.12%
1994	2.10%	2.87%	1.66%	0.94%	2.44%	0.29%
1995	1.80%	0.98%	2.30%	0.94%	3.58%	-0.04%
1996	1.67%	1.75%	1.62%	0.11%	0.67%	-0.13%
1997	1.08%	-0.40%	2.00%	1.53%	4.68%	0.39%
1998	0.17%	-2.94%	2.14%	0.67%	0.73%	0.71%
1999	2.03%	1.98%	2.05%	1.08%	2.24%	0.52%
2000	0.97%	-2.17%	2.18%	0.89%	0.86%	0.73%
2001	0.83%	-0.69%	1.80%	1.20%	2.73%	0.61%
2002	1.23%	1.28%	1.19%	0.79%	2.73%	0.33%
2003	1.35%	-0.49%	2.83%	-0.03%	-1.50%	0.43%
2004	-0.35%	-3.96%	2.56%	0.41%	0.76%	0.22%
2005	1.85%	1.27%	2.32%	-0.07%	-0.25%	0.09%
2006	1.02%	-0.48%	2.62%	-0.52%	-1.07%	-0.21%
2007	1.16%	-0.21%	3.12%	-0.12%	0.00%	-0.02%
2008	-1.51%	-2.67%	1.27%	-0.99%	-2.06%	-0.09%
2009	2.23%	2.57%	1.34%	1.01%	2.73%	-0.46%
2010	-0.51%	-1.65%	1.00%	-0.27%	-0.47%	0.05%
2011	3.54%	6.17%	0.85%	0.50%	0.05%	0.50%
2012	0.56%	1.86%	-0.63%	1.29%	2.90%	0.58%
2013	-0.73%	-2.31%	0.76%	0.03%	0.40%	-0.05%
2014	-1.61%	-4.74%	1.47%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.66%**	**-0.34%**	**1.36%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**0.51%**	**-0.39%**	**0.94%**	**0.53%**	**0.23%**	**0.65%**
1996-2013	**0.92%**	**-0.06%**	**1.72%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**0.28%**	**-0.11%**	**0.86%**	**0.22%**	**0.30%**	**0.15%**

*CMP operated under multiyear rate plans in the years for which results are shaded.

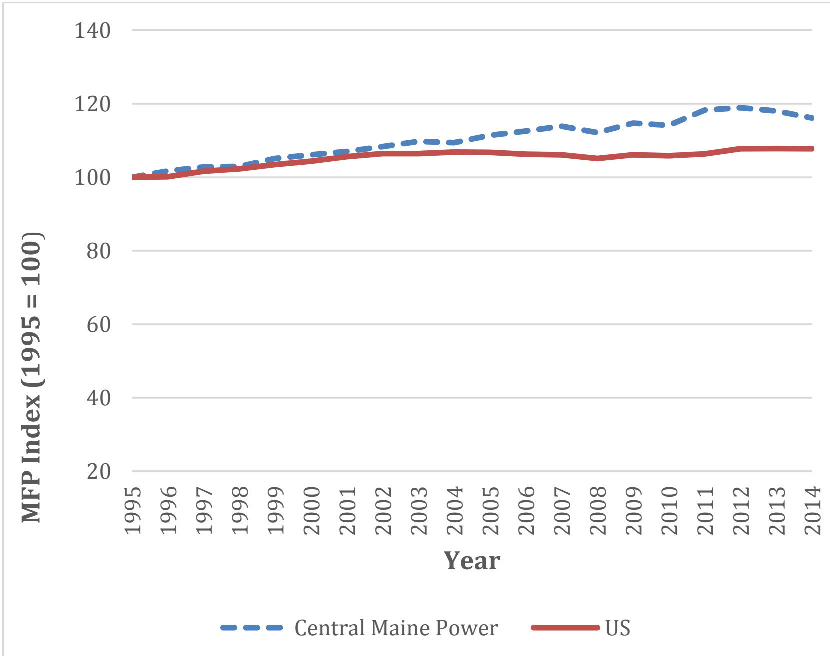

Figure 6. Comparison of Multifactor Productivity Trends of Central Maine Power and the U.S. Sample During Multiyear Rate Plan Periods. The MFP growth of CMP exceeded the industry norm during MRPs.

Marketing Flexibility

During its first rate plan, CMP entered into special contracts with 18 large customers. These contracts featured discounts from tariffed rates in exchange for a guarantee that customers would not attempt to shift their loads to competitors or self-generate during the contract term. In its 1999 10-K filing with the Securities Exchange Commission, CMP described the importance of pricing flexibility and its impacts on the company:

Central Maine believes that without offering the competitive pricing provided in the agreements, a number of these customers would be likely to install additional self-generation or take other steps to decrease their electricity purchases from Central Maine. The revenue loss from such a usage shift could have been substantial.[86]

Service Quality

During the second of CMP's three plans, the Energy and Utilities Committee of Maine's Legislature asked the Public Utilities Commission to investigate effects of the rate plans on service quality performance. This review ultimately resulted in a third-party report.[87] Results of this review were mixed. CMP generally met or exceeded service quality targets. However, performance was uneven. Feeders serving densely populated areas like Portland received greater attention, and these feeders had a greater effect on measured performance systemwide than feeders in rural areas. These performance differences may reflect the fact that reliability PIMs measured only systemwide performance and did not measure performance at a more granular level.

[86] Central Maine Power (1998), p. 81.
[87] Williams Consulting (2007).

Current Status

In 2013, near the conclusion of its third plan, CMP proposed a fourth-generation plan that would have significantly accelerated its revenue growth to help fund a forecasted capex surge.[88] Table 4 shows that CMP's capital productivity trend slowed after 2007. The case ended in a settlement that returned the company to a more traditional regulatory system.[89] A capital tracker for a new customer information system was approved, as was revenue decoupling. While service quality PIMs and the ESM no longer apply, pricing flexibility has continued. No rate case has subsequently been filed.

6.2 California

The California Public Utilities Commission (CPUC) has extensive experience with PBR. This includes the longest experience in North America with MRPs for retail energy utility services. The CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that under the jurisdiction of the Federal Energy Regulatory Commission. Six investor-owned electric utilities (two of which are very large) are regulated, along with natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies. This gives the CPUC strong incentives to contain regulatory costs. MRPs were also facilitated by the CPUC's routine use of forward test years. California's power market was restructured in the 1990s, but two of three large, jurisdictional electric utilities have continued to have sizable generation operations.

The CPUC has limited the frequency of general rate cases using rate case plans for decades. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple large utilities simultaneously. A two-year plan for Southern California Edison was approved in 1980. The standard lag between rate cases was increased to three years in 1984. Longer (e.g., four- or five-year) rate case cycles have since been approved on several occasions.

The CPUC has not always characterized its plans as PBR but did acknowledge the merits of PBR in a 1994 order:

We intend to replace cost-of-service regulation with performance-based regulation. Doing so neither changes the [regulatory] compact's tenets, nor threatens fulfillment of those tenets. We make this change for several reasons.

> First, prices for electric services in California are simply too high. The shift to performance-based regulation can provide considerably stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers. Performance-based regulation also promises to simplify regulation and reduce administrative burdens in the long term. Second, since the utilities' performance-based proposals currently before us leave both industry structure and the utility franchise fundamentally intact, consumers can expect service, safety and reliability to remain at their historically high levels. Third, the utilities' reform proposals are likely to provide an opportunity to earn that is at a minimum comparable to opportunities present in cost-of-service regulation. Finally, performance-based regulation can assist the utilities in developing the tools necessary to make the successful transition from an operating environment directed by government and focused on regulatory proceedings, to one in which consumers, the rules of competition, and market forces dictate. This is of critical importance in our view.[90]

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[88] The Commission stated its opposition to a new plan with a hybrid ARM based on a capital cost forecast.
[89] Maine Public Utilities Commission (2014).
[90] California PUC (1994), pp. 34–35.

The CPUC also has been a national leader in revenue decoupling and PIMs for DSM. This makes California a good case study of the impact performance-based regulation can have on utility DSM as well as cost management. The evolution of MRP design in the state is of further interest given its long history and the diverse situations to which plans have applied.

Plan Design

Attrition Relief Mechanisms

Establishment of multiyear rate case cycles for California energy utilities raised issues of whether and how rates could be adjusted between rate cases. Utilities in the early 1980s were subject to cost pressures from inflation and capacity growth. The three largest utilities invested in nuclear power plants but were denied permission to fund their (often delayed) construction by charging for a return on construction work in progress. The CPUC encouraged large-scale purchases of power from non-utility generators. Revenue decoupling insulated utilities from risks of demand fluctuations but denied them extra revenue from growth in sales volumes, numbers of customers served, and other billing determinants.

Under these circumstances, the CPUC acknowledged that escalation of revenue is typically needed between rate cases.[91] ARMs were thus permitted,[92] and energy costs were addressed by trackers. The out-years of the rate case cycle came to be called *attrition years.* Various approaches to ARM design have been used over the years in California. Predetermined "stepped rate" increases were approved in 1980.[93] However, high inflation encouraged use of inflation measures in ARMs, and many subsequent California ARMs have provided some automatic inflation relief. A hybrid approach to ARM design has been used on many occasions. The broad outline of the first ARMs for Pacific Gas and Electric (PG&E), which started in 1981, is remarkably similar to that of hybrid ARMs that are still occasionally used today.[94]

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that growth in productivity and operating scale also drive cost escalation but assumed that their impact was offsetting.[95]

- Capex per customer was fixed in constant dollars at a five-year average of recent net plant additions, then escalated for inflation.

- Other components of capital cost, like depreciation and return on rate base, were forecasted using cost of service methods. Subsequent hybrid ARMs used in California have involved variations on this basic theme. For example, capex budgets have occasionally been fixed in real terms for several years at forward test year value, then escalated for construction cost inflation. Detailed indexes of utility O&M input price inflation have replaced indexes of

[91] The CPUC has nevertheless persistently maintained that attrition adjustments are not an entitlement even under revenue decoupling and has occasionally rejected their implementation. See, for example, the rejection of PG&E's 2002 attrition adjustment in D.03-03-034.
[92] The ARM was sometimes called an Attrition Relief Adjustment and has in recent years been called a post-test-year mechanism.
[93] California PUC D. 92497 (1980a) for Southern California Gas and California PUC D. 92549 (1980b) for Southern California Edison.
[94] Hybrid ARMs are frequently featured by utilities in their post-test year proposals.
[95] "Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…. We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency." California PUC (1981) Cal. PUC LEXIS 1279; 7CPUC 2d 349.

macroeconomic price inflation in escalation of revenue requirements for O&M expenses. Some plans have permitted utilities to escalate their labor revenue to reflect wage growth in their union contracts.

Several utilities experimented with fully indexed ARMs between 1998 and 2007. For example, PG&E, Southern California Edison, and San Diego Gas & Electric all operated under indexed ARMs.[96] Southern California Gas, America's largest gas distributor, operated under a revenue-per-customer index with inflation and X factor terms. Larger utilities have in recent years most commonly operated under revenue caps with comprehensive stair step escalators. Cost trackers have provided supplemental revenue for advanced metering infrastructure and some reliability-related capex.

Revenue Decoupling

Revenue decoupling has often been used in conjunction with California multiyear rate plans to reduce utilities' incentives to boost retail sales. Revenue decoupling mechanisms called *supply adjustment mechanisms* were first instituted for gas distributors in the late 1970s at the conclusion of a generic proceeding.[97] By 1982, the CPUC approved revenue decoupling mechanisms (called *Electric Revenue Adjustment Mechanisms*) for the three largest California electric utilities. The appeal of decoupling for electric utilities came from several sources:

- Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices.[98] The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility."[99] Utilities played a large role in administering DSM programs (and still do).

- Electric utilities had experimental rate designs such as inverted block rates that were intended to promote conservation but increased sensitivity of utility earnings to demand shifts.

- Utilities experienced substantial risk from other sources, including multiyear rate plans and the CPUC's unwillingness to grant funding for nuclear plant construction work in progress.

Despite a generally positive experience, use of decoupling for California electric utilities fell off in the mid 1990s due, in part, to rules governing the transition to retail competition. There was also some thought that DSM might be provided in the future by independent marketers. A return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk during the California power crisis.[100] The three largest electric utilities recommenced decoupling, which continues today.

[96] Indexed ARMs are still used for California energy utilities serving smaller state loads. For example, a 2007 decision in a PacifiCorp rate case approved a settlement that outlined an MRP featuring a price cap index and a three-year term. The index has escalated base rates to reflect growth in an annual forecast of CPI less a productivity adjustment of 0.5 percent. Supplemental revenue is permitted for the California portion of major plant addition costs exceeding $50 million. Parties later agreed to defer PacifiCorp's scheduled 2010 rate case for one year and adopted an identical MRP in the 2011 general rate case. The CPUC agreed to extend PacifiCorp's renewed MRP for several additional years, and the utility will not file a new rate case until 2019 at the earliest.
[97] CPUC Decision 88835, Case No. 10261, May 1978.
[98] Fossil fueled generators in California burned oil, gas or both.
[99] CPUC Decision 85559, March 1976, p. 489.
[100] See California Public Utilities Code (2001).

Demand-Side Management PIMs

California was also an early innovator in the area of DSM PIMs. The first experimental DSM PIMs were implemented in 1990. These measures did not survive deregulation of California's electricity market later in the decade.

In 2007, California reintroduced DSM PIMs for larger utilities through the Risk-Reward Incentive Mechanism. This mechanism featured a relatively complex shared savings approach to compensation. Each utility had targets for three metrics (if applicable): electricity savings, gas savings and peak demand reductions. Under the original incentive design, utilities could receive a reward of up to 12 percent of the dollar value of evaluated net benefits of eligible DSM programs if they performed strongly on all three metrics. Conversely, they would be penalized if they fell below 65 percent of the target for any one of the three metrics. Critically, utility financial outcomes would be based on evaluated (*ex post*), not predicted (*ex ante*), net benefits. That meant that utility outcomes were not known until program evaluations were completed. This choice extended the process and added complexity. However, the CPUC felt it important to reward or penalize how programs actually performed in order to properly align utility incentives and protect ratepayers from adverse outcomes.[101]

The Risk-Reward Incentive Mechanism was implemented for the first time at the end of the 2006–2008 utility program cycle. Disputes over net benefits soon developed, as the CPUC's evaluation consultants estimated program results that substantially differed from the utilities' estimates and implied very different financial outcomes, in part due to the sharp earnings cutoffs in the mechanism's reward structure.[102] Disputes stretched over several years and proved intractable enough that the CPUC modified the mechanism. It based net benefit calculations on parameters (for example, net-to-gross ratios) estimated before programs were implemented, as well as on actual program delivery outcomes.[103] It also lowered the incentive to a flat 7 percent of net benefits and eliminated the possibility of penalties. Savings used to calculate rewards were in between the utilities' and the CPUC's estimates. For programs from 2010 to 2012, the CPUC simplified these PIMs, establishing rewards conditioned primarily on utility spending (management fees) rather than evaluated program performance.

In 2013, the CPUC adopted the Energy Savings Performance Incentive.[104] Under this mechanism, performance awards for many programs were based on energy savings delivered, not net benefits. Energy savings were not discounted, unlike energy benefits in the earlier net benefits calculation. Thus, the revised mechanism provided greater relative rewards for deeper, longer-lived savings. The revised mechanism did not include a potential penalty and avoided sharp earnings cutoffs of the Risk-Reward Incentive Mechanism. Rewards under the Energy Savings Performance Incentive were expected to be lower, and the incentive also capped the maximum achievable reward at a lower level, compared to the Risk-Reward Incentive Mechanism, largely due to the absence of an earnings penalty.

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[101] See CPUC, 2007b, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf.

[102] The reward/penalty function consisted of four tiers: a penalty if evaluated energy/capacity savings were less than 65 percent of a target; a dead band of no reward or penalty if savings were between 65 percent and 85 percent of a target; a 9 percent shared savings reward if savings were between 85 percent and 100 percent of a target; and a 12 percent shared savings reward if savings exceeded a target. Each transition between tiers created a sharp reward discontinuity. A small change in the evaluated savings could produce a big change in the reward. Further exacerbating these issues, a utility was paid based on the worst of the three outcomes. For example, if a utility fell below 65 percent of any of the three targets, it earned a penalty even if it performed strongly on the other two. In one case, a utility's estimated savings implied a $180 million reward; the evaluation consultants' estimates implied a $75 million penalty. See Chandrashekeran et al. (2015).

[103] This CPUC decision was controversial, with one commissioner objecting that the revised mechanism largely eliminated the actual performance incentives and ratepayer protections provided by the prior, *ex post*-based mechanism. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128882.pdf.

[104] CPUC (2013).

The Energy Savings Performance Incentive calculates savings *ex post*, reintroducing one of the challenges under the previous incentive mechanism. Some parameters that are considered relatively certain were locked in *ex ante*; those deemed "sufficiently uncertain" by the CPUC required *ex post* measurement. In reintroducing *ex post* calculations, the CPUC emphasized the need to protect ratepayers from paying out rewards based on overly optimistic *ex ante* projections, arguing that this objective outweighed the utilities' desire for revenue certainty and justified potential disputes over *ex post* savings calculations. The Energy Savings Performance Incentive rewarded both codes and standards support programs and "non-resource" programs (those that cannot support an energy savings calculation — largely market transformation programs) using a management fee based on utility dollars spent. The Risk-Reward Incentive Mechanism had not rewarded these programs. Incentives distributed for 2013 and 2014, as well as some rewards for 2015, have prompted far fewer disputes over process and savings estimates.

The CPUC recently developed a pilot PIM program for DERs such as distributed generation and storage. The CPUC approved a management fee mechanism that would offer investor-owned electric utilities 4 percent of annual payments made to DER providers pretax as an incentive to use third-party DERs to cost-effectively displace or defer the need for capex for traditional distribution system investments that were previously planned and authorized.[105] Utilities are required to pursue at least one project and have the option to pursue three more.

The CPUC also authorized the utilities to keep any savings from capex underspends due to DER that had been previously approved until the next general rate case.[106] Estimated costs of the DER and administration of the solicitation are recoverable with interest up to a preapproved cap when rates are reset in the next rate case. Administrative costs above the cap will be reviewed for reasonableness in the next rate case.

In their procurement decisions, utilities are required to consider the net market value of potential DER pilot projects. The net market value calculation includes a broad range of factors, including capacity, energy, ancillary grid services, costs of grid integration, deferred distribution and transmission system costs, and the cost of the DER procurement contract. During the pilot, each of the three major electric utilities are allowed to use different methods for ensuring that DERs rewarded by the incentive are incremental to the utility's existing plans and efforts as governed by other Commission proceedings, in order to test the performance of each method.

Other MRP Provisions

Other characteristics of California electric utility regulation also merit note:

- The CPUC decided in Decision 89-01-040 to address target rates of return on capital of all energy utilities in a separate annual proceeding. This meant that revenue requirements generated by ARMs often have been subject to supplemental rate of return adjustments. Some of these adjustments have been formulaic.[107]

[105] California PUC (2016).
[106] This is not a change from current California regulatory practices, but was explicitly stated nonetheless.
[107] For example, San Diego Gas & Electric's Market Indexed Capital Adjustment Mechanism, approved in 1996, featured a trigger mechanism that updated the cost of capital if bond yields deviated from the benchmark by a specific amount. A similar mechanism was established in 2008 for all large California utilities.

- Cost allocation and rate design issues are commonly addressed in a second phase of a general rate case. In attrition years, utilities have additional opportunities to adjust cost allocations and rate designs in rate design "windows."[108]

- Use of capital cost trackers has been limited in California, due in part to the fact that hybrid and forecasted ARMs have been prevalent. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants and AMI.

- The CPUC has experimented with incentivized trackers for generation fuel and purchased power expenses. For example, San Diego Gas and Electric had a PIM that assessed the effectiveness of its generation and dispatch costs through simulations of annual production costs using expected and actual data. PIMs also have been used for nuclear generation plant capacity factors where sharing of energy cost variances would occur if the capacity factor of a facility was above or below the dead band.

- The CPUC has approved MRPs for generating facilities, independent of other utility assets. For example, in the late 1980s, the CPUC approved an MRP for PG&E's Diablo Canyon nuclear plant where it was permitted to charge an escalating price per MWh for power produced. This charge initially compensated PG&E for capital costs as well as O&M expenses,[109] strengthening the company's incentive to keep the plan running. The Diablo Canyon rate plan expired in 2001.

- Earnings sharing mechanisms and PIMs for service quality have not been routinely featured in California MRPs. During the experimentation with index-based ARMs, earnings sharing mechanisms and service quality PIMs were more common. The CPUC has monitored service quality performance since at least the 1990s.

Outcomes

Cost Control

Table 5 and Figure 7 compare the distributor productivity trends of California's three largest electric utilities to the norm for our full U.S. electric utility sample. Over the full 1986–2014 period during which MRPs have been extensively used in California, the MFP growth of these utilities averaged a 0.14 percent annual *decline,* whereas the MFP of our full U.S. sample averaged 0.43 percent annual *growth.*[110] Thus, the MFP growth of the California utilities was 57 basis points *slower* on average. All three utilities had subpar trends. The capital productivity growth of California utilities has been especially slow. In the 1980–1985 period, before MRPs were widely used, MFP trends of these utilities and the full sample were similar.

[108] Any attrition relief adjustment that the ARM puts in motion is pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations, as amended by changes effected in the rate design windows.
[109] In 1997, however, the plan was revised so that the mechanism recovered only the incremental costs of the plant (costs of O&M and new plant additions). The ongoing recovery of sunk costs was achieved through a separate transition charge.
[110] The MFP growth trends of California utilities were fairly similar to those for the full sample during the six-year 1980 to 1985 period before MRPs became common.

These unflattering results may reflect special California operating challenges. However, the results may also reflect ineffective plan design. We have noted that California ARMs have often based a utility's budget for plant additions on its own historical additions, and passed through the escalation of a utility's union wages.

Table 5. How the Power Distributor Productivity Growth of Larger California Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	California Average			U.S. Sample Average		
	MFP	O&M PFP	Capital PFP	MFP	O&M PFP	Capital PFP
1980	-0.10%	-2.39%	0.96%	-0.49%	-4.19%	1.24%
1981	0.65%	-0.85%	1.22%	0.17%	-2.42%	1.25%
1982	-0.54%	-3.92%	0.78%	0.87%	-1.20%	1.53%
1983	-0.20%	-3.46%	0.99%	0.51%	-0.38%	0.98%
1984	1.43%	-0.20%	2.00%	1.27%	-0.22%	1.79%
1985	1.27%	-1.44%	1.78%	0.95%	-0.21%	1.37%
1986	0.96%	2.23%	0.61%	0.91%	0.88%	0.97%
1987	0.58%	2.56%	0.02%	0.44%	-0.12%	0.68%
1988	1.86%	10.04%	-0.35%	0.57%	1.55%	0.24%
1989	0.80%	3.51%	-0.04%	0.26%	0.00%	0.23%
1990	0.35%	3.49%	-0.71%	0.18%	0.64%	-0.05%
1991	-1.13%	-0.85%	-1.18%	-0.03%	0.58%	-0.32%
1992	-0.71%	0.98%	-1.26%	0.48%	1.61%	0.10%
1993	-1.45%	-1.66%	-1.38%	0.45%	1.19%	0.12%
1994	0.01%	3.17%	-0.93%	0.94%	2.44%	0.29%
1995	0.27%	0.02%	0.32%	0.94%	3.58%	-0.04%
1996	1.43%	3.26%	0.89%	0.11%	0.67%	-0.13%
1997	0.41%	-1.07%	0.87%	1.53%	4.68%	0.39%
1998	-0.24%	-1.81%	0.32%	0.67%	0.73%	0.71%
1999	-0.53%	1.21%	-1.08%	1.08%	2.24%	0.52%
2000	-0.32%	1.19%	-0.92%	0.89%	0.86%	0.73%
2001	1.63%	1.41%	1.76%	1.20%	2.73%	0.61%
2002	-1.21%	-3.73%	-0.45%	0.79%	2.73%	0.33%
2003	-1.21%	-3.63%	-0.29%	-0.03%	-1.50%	0.43%
2004	-0.14%	0.34%	-0.31%	0.41%	0.76%	0.22%
2005	-0.90%	-2.64%	-0.12%	-0.07%	-0.25%	0.09%
2006	-1.36%	-3.95%	-0.06%	-0.52%	-1.07%	-0.21%
2007	-0.57%	-0.56%	-0.58%	-0.12%	0.00%	-0.02%
2008	-1.44%	-2.17%	-0.80%	-0.99%	-2.06%	-0.09%
2009	0.83%	2.22%	-0.56%	1.01%	2.73%	-0.46%
2010	-1.15%	-0.58%	-1.47%	-0.27%	-0.47%	0.05%
2011	-1.94%	-1.12%	-2.29%	0.50%	0.05%	0.50%
2012	-0.39%	0.82%	-0.91%	1.29%	2.90%	0.58%
2013	1.33%	3.94%	0.23%	0.03%	0.40%	-0.05%
2014	0.04%	3.81%	-1.28%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**-0.05%**	**0.23%**	**-0.12%**	**0.45%**	**0.53%**	**0.43%**
1980-1985	**0.42%**	**-2.04%**	**1.29%**	**0.55%**	**-1.44%**	**1.36%**
1986-2014	**-0.14%**	**0.70%**	**-0.41%**	**0.43%**	**0.93%**	**0.24%**
2008-2014	**-0.39%**	**0.99%**	**-1.01%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

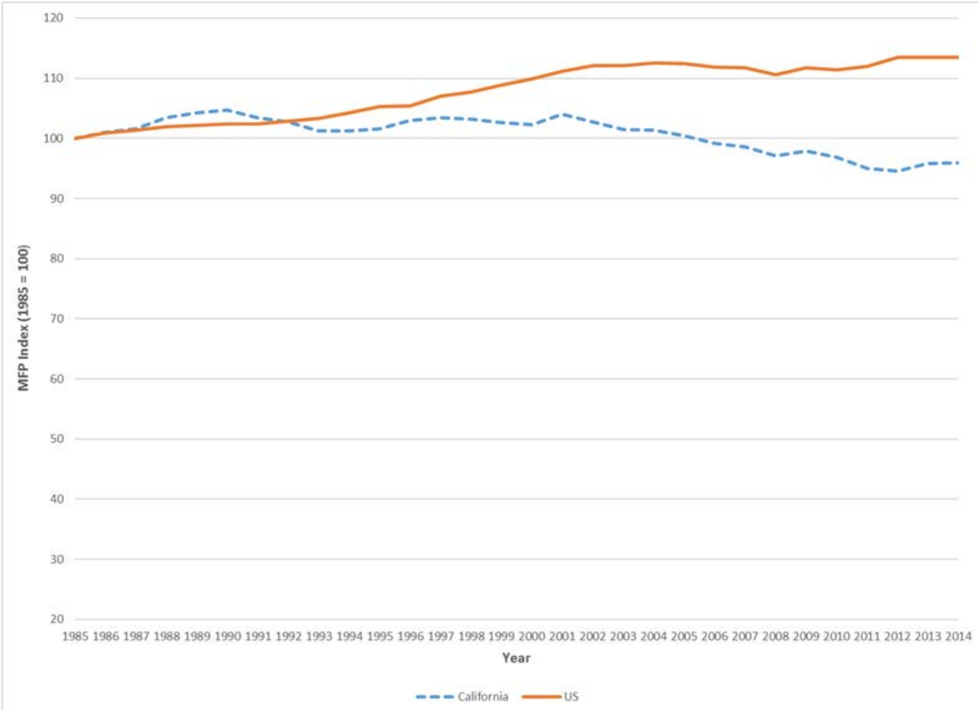

Figure 7. Comparison of Multifactor Productivity Trends of California Distributors and the U.S. Sample during Multiyear Rate Plan Periods. MFP growth of California utilities has fallen short of industry norms under MRPs.

DSM Programs

California electric utilities have typically operated large DSM programs, traditionally ranked near the top of most surveys. Since 1996, the American Council for an Energy-Efficient Economy (ACEEE) has issued annual scorecards evaluating state efforts and achievements in energy efficiency.[111] These surveys include estimates of DSM spending (or budgets) as a percentage of utility revenue. In the eight years for which data were available since 2006, California has averaged a 5.5 ranking out of 51 U.S. jurisdictions (with 1 the highest possible ranking).

Rate Designs

California has also been a national leader in use of rate designs that encourage DSM. For example, inclining block rate designs intended to encourage conservation have been mandated for residential customers since 1976.[112] Until recently, California investor-owned utilities (IOUs) had a very steep inclining block rate structure for these customers, consisting of four tiers ranging from \$0.13/kWh for the lowest tier of usage to \$0.42/kWh for the highest tier.[113] In a 2015 decision,[114] the CPUC reduced the number of tiers to two (plus a third tier for very high energy users) and specified that the second tier's price should be 25 percent higher than the first. The result is that the lowest tiers now face a higher price

[111] Berg et al. (2016).
[112] California Public Utilities Code, section 739.
[113] St. John (2015).
[114] CPUC (2015b).

than before, while the higher tiers face a lower one — in other words, a flatter rate structure. This reduces what was formerly a very significant incentive for efficiency and distributed generation deployment for customers using large amounts of electricity. On the other hand, it raises this incentive for customers with lower usage.

Time of use rates are currently optional for residential customers. The CPUC has ordered the IOUs to transition most residential customers to default time of use pricing in 2019.[115] Most commercial and industrial IOU customers in California already face seasonally differentiated default time of use prices, which were introduced in 2014. While these customers can opt into non-time-differentiated rates, few have done so.

Service Quality

California's regulatory system for service quality is more reactive than proactive and has featured several investigations to assess utilities' service quality performance. An early investigation focused on whether PG&E had adequately responded to severe storms in 1995. In its decision, the CPUC ordered standardized service quality and reliability reporting requirements to be developed. Southern California Edison and Sempra had service quality PIMs in rate plans with index-based ARMs during the late 1990s and early 2000s.

Edison's service quality PIMs included one for customer satisfaction, as measured by a survey. In 2003 a whistleblower brought to the utility's attention that fraud had occurred in the customer satisfaction surveys. The company investigated the claims, confirmed that there had been misconduct, expanded the investigation to include the other PIMs, and notified the CPUC.

The Commission opened its own investigation on the matter. It found that Southern California Edison had provided false and misleading data in support of its performance claims on the customer satisfaction survey and health and safety PIMs. The Commission's decision required a refund of rewards that Edison had obtained through false reporting, made the utility forego recovery of additional rewards through these PIMs, and fined the utility an additional sum. The Commission was particularly concerned that the utility had gamed an incentive mechanism, stating that:

> Incentive mechanisms, such as the [PIMs], require a great deal of trust between the Commission and the utility's entire management. In turn, the utility's management must communicate through its practices, rules, and corporate culture that the data submitted to the Commission that impacts the incentive mechanisms must be completely accurate and timely. Increasingly, this Commission is turning to incentive mechanisms in order to align the interests of ratepayers and shareholders and to achieve desirable policy outcomes in the most cost effective and least burdensome manner. If the Commission is to continue to rely on and potentially create new incentive mechanisms, we must be able to trust the utilities to be accurate, timely, and completely honest about their reporting, and further, we must be vigilant against abuse and appropriately penalize violations in order to safeguard the integrity of incentive mechanisms going forward for all utilities.[116]

[115] Ibid.
[116] CPUC (2008), p. 102–103.

6.3 New York

New York has also had a long history with MRPs for energy utilities. Plans have been widely used there since the mid-1990s. Experience with MRPs has spanned some years when electric utilities were still vertically integrated, and more than 15 years after industry restructuring was completed. DSM programs are provided primarily by a state agency, the New York State Energy Research and Development Authority, but utilities also have some programs. MRPs are usually outcomes of negotiated settlements in regulatory proceedings.

The inclination of New York's Public Service Commission and Department of Public Service (DPS) to adopt MRPs has several root causes. Regulatory cost savings can be sizable, since New York's economy is large and there are six investor-owned electric utilities (and even more investor-owned gas utilities) to regulate.[117] MRPs also have been facilitated by New York's long-standing use of forward test years in rate cases. One of the earliest MRPs, for Orange & Rockland Utilities, was motivated in part by concerns about performance incentives. The Commission stated in approving the plan:

> Economic regulation, like most acts of market intervention, can have unintended and undesirable consequences. In the case of a regulated monopoly, the consequence most frequently watched for and least easily avoided is operating inefficiency within the firm, resulting from the "cost plus" nature of price controls. In theory, the [MRP] should encourage greater operating efficiency, because the period of regulatory lag during which the company would be allowed to retain savings from productivity gains would be longer.[118]

Reducing regulatory cost has also been cited in the Commission's support of MRPs. For example, in a 2008 rate case decision for Consolidated Edison, the Commission discussed the drawbacks of annual rate cases.

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing — the third in three years — ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[119]

The relatively poor performance of several New York utilities after a series of storms including Superstorm Sandy led the governor to issue an order establishing a commission, called the Moreland Commission on Utility Storm Preparation and Response (Moreland Commission), to investigate and review the storm preparedness of New York's electric utilities, the adequacy of regulatory oversight, and the jurisdiction, responsibility, and mission of New York's energy agency and authority functions.[120] The findings of the Moreland Commission encouraged the governor to push for a reassessment of electric utility regulation more generally. We discuss some Moreland Commission findings further below.

[117] A seventh investor-owned electric utility, Long Island Lighting, was transferred to the state-owned Long Island Power Authority during the 1990s.
[118] New York Public Service Commission (1990).
[119] New York Public Service Commission (2009), p. 282.
[120] Moreland Commission (2013a).

In 2014 New York's Public Service Commission initiated a generic proceeding to consider how the regulatory system of power distributors and their marketplace roles should evolve in an era of rapid change in distribution, metering, and DER costs and technologies.[121] This came to be called the "REV" proceeding after a Department of Public Service Staff report entitled *Reforming the Energy Vision*.

Track One of the proceeding considered appropriate roles of power distributors going forward. Utilities are envisioned as distributed system platform providers that accommodate customer-side DERs and energy service companies and may offer new services that use smart grid technologies. Utilities are now required to file Distribution System Integration Plans that among other things, consider the use of DERs to avoid capex. The first filings were made last summer.[122] Track Two of the proceeding has addressed miscellaneous ratemaking issues such as rate designs and MRP design. We discuss the outcomes further below.

Plan Designs

New York rate plans have featured forecasted ARMs.[123] Since decoupling has been common, most ARMs have effectively been revenue caps.[124] A "one-way" net plant reconciliation ("claw back") mechanism has been added to MRPs in recent years which returns to customers benefits of capex underspends.[125] Plans typically have a term of only three years. In the early 1990s and since 2007, plans also typically have included revenue decoupling and PIMs for utility DSM. Where New York utilities do not have an approved MRP but have revenue decoupling, they often have filed frequent rate cases. MRPs also typically have featured asymmetrical ESMs that share only surplus earnings.

Service quality PIMs are common in New York and are sometimes extensive. There are PIMs for customer service as well as reliability. In addition to these PIMs, service quality standards for SAIDI and CAIDI have been in place since 1991 which, if breached, require a corrective action plan to be filed with the Commission. Consolidated Edison's most recent plan had separate PIMs for its radial and network systems. This plan also featured PIMs for performance following major events (e.g., outages) and a wide variety of asset management activities.

New York plans during the late 1990s and early 2000s were somewhat different from plans that were approved in the early 1990s and after 2007. These plans did not feature revenue decoupling or DSM PIMs, but retained ESMs and service quality PIMs. Several plans featured rate freezes often tied to restructuring plans or merger approvals. A plan for Niagara Mohawk had a 10-year term.

The Commission issued an order on Track Two of its REV proceeding in 2016, including the design of its regulatory system.[126] Among the specific issues addressed are the following:

- The net plant reconciliation mechanism will be reformed to enable utilities to profit from DERs that displace previously approved capital projects. Because this will often be achieved through increased operating expenses, rather than capital expenses, the existing mechanism would require utilities to forfeit approved capital earnings. This creates a disincentive for utilities to adopt lower cost DER alternatives. To address this, the Commission will permit utilities to retain earnings on previously approved, traditional utility capital projects included

[121] New York Public Service Commission (2014a).
[122] Walton (2016a).
[123] Indexed ARMs have, however, been proposed by utilities on several occasions.
[124] From the late 1990s to mid-2000s, revenue decoupling was not featured in New York regulation. These plans were price caps where base rates were specified for each year of the plan.
[125] An underspend occurs if utility capex is less than the budget which the ARM provides.
[126] New York Public Service Commission (2016a).

in base revenue, even if these projects do not materialize, until rates are reset in the next rate case. To qualify for this treatment, a utility must demonstrate that DSM or other types of DERs displaced the capital project. The Commission expressed interest in considering further modifications to the claw back mechanism in the future, such as sharing any realized savings between the utility and customers over a longer time horizon.

- As utilities transition to a platform provider role, the Commission expects a growing share of their income to be Platform Service Revenues,[127] new revenues arising from the operation or facilitation of distribution-level markets.

- *Earnings Adjustment Mechanisms* are New York's term for performance incentive mechanisms. They are to focus on outcomes, rather than on utility inputs or the attainment of specific program targets, and are not restricted to items under the utility's direct control. The Commission expects these adjustment mechanisms to be most important in the near term, serving as a "bridge" to the time when markets provide utilities with a sizable share of revenue in the form of platform services revenues.

  To avoid encouraging utilities to grow rate base, the Commission stated that Earnings Adjustment Mechanisms should not take the form of basis-point adjustments to earnings (though they may be designed in reference to basis-point changes and fixed in dollar amounts before the mechanisms take effect). Mechanisms also generally should avoid estimated counterfactuals in order to reduce controversy and cost. In addition, they should be financially meaningful, encourage strategic, portfolio-level approaches beyond narrow programs, and generally be structured on a multiyear basis.

  Though specific metrics and associated Earnings Adjustment Mechanisms will be worked out in future proceedings, the Commission provided requirements and guidance in several areas:

  - *System Efficiency.* The Commission will require utilities to propose system efficiency Earnings Adjustment Mechanisms that address both peak reduction and load factor. Initial proposals should include only the possibility of positive adjustments.

  - *Energy Efficiency.* Pending recommendations from the Clean Energy Advisory Council based on State Energy Plan and Clean Energy Standard goals, energy efficiency Earnings Adjustment Mechanisms will be redesigned. One focal point will be systemwide electric usage intensity (e.g., measured as kWh per capita, kWh per customer or kWh per unit of GDP).

  - *Interconnection.* An Earnings Adjustment Mechanism will address interconnection of distributed generation and storage projects over 50 kW. It will include a threshold tied to meeting timeliness requirements, and a positive adjustment based on evaluations by interconnection customers of application quality and applicant satisfaction. Negative adjustments may also be considered in individual utility proceedings. The Track Two order required the utilities to develop an Earnings Adjustment Mechanism for distributed generation connection timeliness, customer satisfaction with distributed generation interconnection processes and audits of failed distributed generation interconnection applications.

[127] One potential problem with Platform Service Revenues is that margins from them are netted off of the revenue requirement in each rate case. Another is that competitors will endeavor to limit the role of utilities in the provision of new services. MRPs can help utilities retain margins from these new revenues for several years.

- *Customer Engagement.* The Commission declined to implement an Earnings Adjustment Mechanism related to general customer engagement. However, the Commission will consider proposals in this area. For example, Earnings Adjustment Mechanisms could reward utilities for increased customer participation in time-varying rates or adoption of ground-source heat pumps and electric vehicles.

- *Scorecards.* The Commission plans to use scorecard metrics to track utility progress, which could serve as the basis for Earnings Adjustment Mechanisms in the future.

- Utilities may also earn new revenues from displacing traditional infrastructure projects with non-wires alternatives (NWAs) in other ways. The Brooklyn Queens Demand Management program of Consolidated Edison (Con Ed) is the best-known example.[128] Approved by the Commission in 2014, its goal is to use DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs.[129] In the absence of this program, upgrades needed by 2017 would have an estimated cost of approximately $1 billion and included a new area substation, a new switching station at an existing station, and new subtransmission feeders.[130]

  To overcome the disincentive for Con Ed to pursue NWA projects, the Commission adopted the following performance incentives contingent on satisfactory performance on the company's existing reliability PIMs:[131]

  1. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred Brooklyn-Queens program costs up to a cap. These amounts would be recovered over a 10-year period.

  2. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on program costs contingent on performance.

  An NWA incentive mechanism was approved in 2016 which gives Central Hudson Gas and Electric a 30 percent share of savings associated with delaying investments in traditional power plant structures and reductions in wholesale capacity requirements. Program costs will be amortized and recovered over the subsequent five-year period.[132]

- The Commission declined to extend the terms of MRPs from three to five years in recognition of the need for a high level of regulatory oversight during the early REV transitional period. However, the Commission stated that longer plans had significant potential to achieve long-term benefits and declined to preclude parties from pursuing longer plans if desired.

Consolidated Edison was the first utility to have its rate case litigated after the Track Two decision was issued. This placed the company in the position of being the first to implement several REV features.[133] A separate decision on the same day as the rate case decision approved an incentive mechanism that allowed

[128] For further discussion, see Walton (2016b).
[129] New York Public Service Commission (2014b).
[130] Concurrently with the BQDM program, Con Ed is undertaking about 17 MW of traditional infrastructure investments.
[131] The utility proposed an additional shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50 percent share of the annual net savings realized by customers. The Commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.
[132] New York Public Service Commission (2016b).
[133] In the case of New York State Electric & Gas and Rochester Gas & Electric, Earnings Adjustment Mechanisms are being developed as a compliance filing to the rate case.

Con Ed to receive 30 percent of the net benefits of NWA projects, except on the Brooklyn Queens Demand Management program.[134] Costs of NWA projects will be recovered over a 10-year period. The net plant reconciliation mechanism was revised to allow Con Ed to use the revenue requirements that would otherwise be refunded to customers as a result of capex underspends from successful DER deployments to offset the revenue requirements of any related non-wires alternative project first.

Earnings adjustment mechanisms and metrics were approved to encourage superior Consolidated Edison performance in several areas.

- In the area of energy efficiency and demand response, two metrics are relied on to assess Con Ed's performance. The first encourages Con Ed to increase its incremental gigawatt-hour (GWh) savings from energy efficiency programs. The second metric encourages Con Ed to improve its demand response effectiveness as measured by incremental system peak megawatt (MW) reductions from energy efficiency programs.

- With respect to deployment of incremental DERs, a metric encourages incremental use of DERs from solar energy, combined heat and power, battery storage, demand response and beneficial electrification, such as thermal storage, heat pumps and electric vehicle charging.

- Measurement of customer load factors is intended to encourage Con Ed to improve those of poor load factor customers. This metric is customer-specific and compares the customer's average load to their peak. Due to the need to conduct further research on this metric, no targets or incentives were assigned to this metric for the first year.

- Metrics also measure Con Ed's weather-normalized average use adjusted for incremental beneficial usage. One measures residential use per customer; another measures commercial use per employed person in Con Ed's service territory.

- Separate metrics are used to assess Con Ed's performance on distributed generation interconnection timeliness, customer satisfaction with distributed generation interconnections, and independent audits of failed distributed generation interconnection applications. Development of specific targets was deferred beyond the rate case, so that no Earnings Adjustment Mechanism will apply for the first rate year.

All of the proposed Earnings Adjustment Mechanisms will be reviewed each year for potential revisions. The incentives increase for each Earnings Adjustment Mechanism during the term of the MRP, with the maximum reward exceeding $50 million in year three of the plan.

[134] New York Public Service Commission (2017).

Outcomes

Utility Cost

Table 6 and Figure 8 compare the power distributor productivity trends of New York electric utilities to the averages for our full U.S. electric utility sample. From 1980–1993, before MRPs became commonplace, the MFP growth of New York power distributors averaged 0.98 percent annually. This was 51 basis points above the average for sampled power distributors nationally. Over the 1994–2014 period during which MRPs have been prevalent, the MFP trend of the New York utilities averaged 0.54 percent annually, whereas the average for our full national sample was a similar 0.45 percent. Capital productivity growth was more rapid in New York but O&M productivity growth was slower. Evidence that MRPs have improved cost performance is therefore not strong. This is not surprising since New York's approach to MRP design is conservative, with short rate case cycles.

Table 6. How the Power Distributor MFP Growth of New York Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	New York Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	0.78%	-1.47%	1.42%	-0.49%	-4.19%	1.24%
1981	1.57%	1.73%	1.42%	0.17%	-2.42%	1.25%
1982	-0.28%	-4.42%	1.63%	0.87%	-1.20%	1.53%
1983	1.75%	1.82%	1.65%	0.51%	-0.38%	0.98%
1984	2.28%	1.81%	2.37%	1.27%	-0.22%	1.79%
1985	1.74%	-0.19%	2.39%	0.95%	-0.21%	1.37%
1986	1.89%	2.03%	1.82%	0.91%	0.88%	0.97%
1987	0.84%	-1.83%	1.78%	0.44%	-0.12%	0.68%
1988	1.94%	2.09%	1.87%	0.57%	1.55%	0.24%
1989	1.29%	1.73%	0.98%	0.26%	0.00%	0.23%
1990	0.01%	-1.19%	0.56%	0.18%	0.64%	-0.05%
1991	-1.65%	-4.97%	-0.12%	-0.03%	0.58%	-0.32%
1992	1.38%	4.27%	0.18%	0.48%	1.61%	0.10%
1993	0.16%	-0.35%	0.35%	0.45%	1.19%	0.12%
1994	1.67%	4.18%	0.61%	0.94%	2.44%	0.29%
1995	0.65%	0.12%	0.82%	0.94%	3.58%	-0.04%
1996	0.29%	-0.54%	0.59%	0.11%	0.67%	-0.13%
1997	0.16%	-1.63%	0.96%	1.53%	4.68%	0.39%
1998	-0.29%	-5.04%	1.70%	0.67%	0.73%	0.71%
1999	1.70%	1.78%	1.45%	1.08%	2.24%	0.52%
2000	0.60%	1.22%	0.18%	0.89%	0.86%	0.73%
2001	2.23%	2.96%	1.91%	1.20%	2.73%	0.61%
2002	-0.33%	-5.18%	1.18%	0.79%	2.73%	0.33%
2003	1.51%	1.37%	1.66%	-0.03%	-1.50%	0.43%
2004	0.90%	3.65%	-0.53%	0.41%	0.76%	0.22%
2005	-1.50%	-1.35%	-1.46%	-0.07%	-0.25%	0.09%
2006	-1.08%	-2.58%	-0.01%	-0.52%	-1.07%	-0.21%
2007	2.10%	3.91%	0.47%	-0.12%	0.00%	-0.02%
2008	-0.16%	-0.54%	0.58%	-0.99%	-2.06%	-0.09%
2009	2.26%	3.65%	0.32%	1.01%	2.73%	-0.46%
2010	-1.32%	-3.61%	0.90%	-0.27%	-0.47%	0.05%
2011	3.79%	7.39%	0.72%	0.50%	0.05%	0.50%
2012	1.19%	0.67%	0.53%	1.29%	2.90%	0.58%
2013	-2.93%	-6.18%	-0.14%	0.03%	0.40%	-0.05%
2014	-0.09%	-1.02%	0.51%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.72%**	**0.12%**	**0.89%**	**0.45%**	**0.53%**	**0.43%**
1980-1993	**0.98%**	**0.08%**	**1.31%**	**0.47%**	**-0.16%**	**0.72%**
1994-2014	**0.54%**	**0.15%**	**0.62%**	**0.45%**	**0.99%**	**0.24%**
2008-2014	**0.39%**	**0.05%**	**0.49%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs for a majority of New York's electric utilities were in effect.

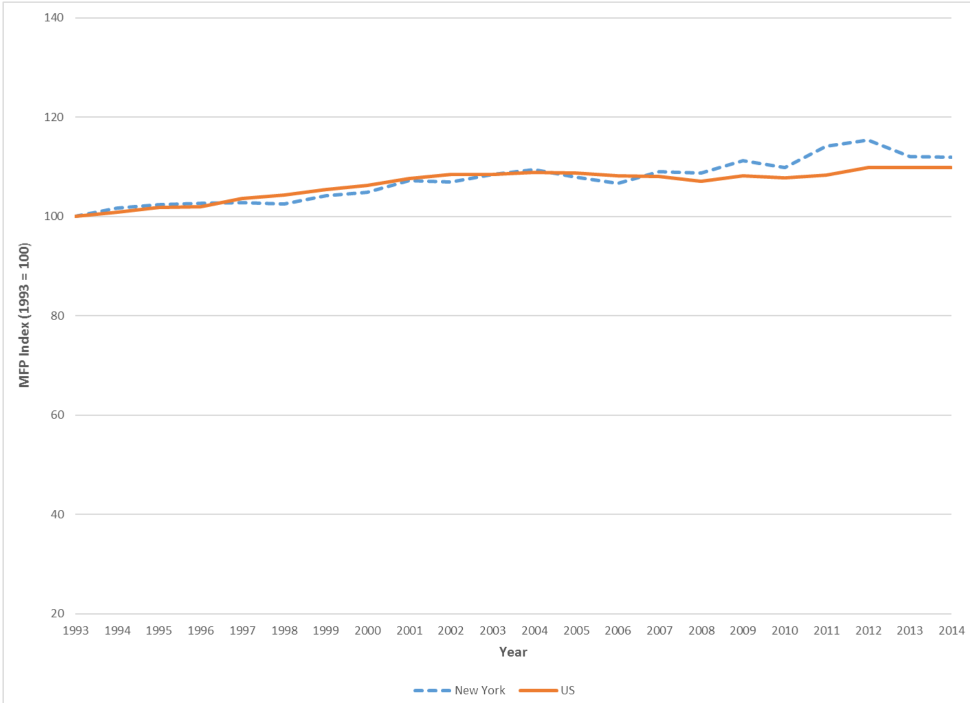

Figure 8. Comparison of Multifactor Productivity Trends of New York Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of New York distributors has modestly exceeded industry norm under MRPs.

Rate Designs

In recent years New York utilities have had some of the highest residential customer charges in the United States. AMI is not pervasive.[135] The Commission recently directed utilities to develop strategies to increase opt-in of mass market (i.e., residential and small commercial) customers to time-of-use rates.[136] Utilities are to develop promotional and customer engagement tools with reference to best practices in states where participation in opt-in time-varying pricing programs is higher.

Utilities also will offer Smart Home Rates as demonstration projects. These rates will combine granular time-varying rates with location and time-based compensation for DERs, in a way that is managed automatically to optimize value for both the customer and system. Smart Home rates are intended to allow a customer to be compensated for multiple services (e.g., load shifting, peak reduction, voltage regulation).

In the longer term, the Commission supports time-sensitive rates for both commodity and delivery services. It has directed its staff to propose a study of the potential bill impacts of a range of mass-market rate reforms, including time-of-use and demand charges. The Commission identifies Smart Home Rates as "the model for a rate design that should become the widely-adopted norm as markets mature."[137]

[135] At least one utility, Consolidated Edison, is beginning a large-scale deployment of AMI.
[136] New York Public Service Commission (2016a).
[137] New York Public Service Commission (2016a), p. 135.

Service Quality

New York's customer service and reliability PIMs generally have been successful. Over the past five years, New York utilities have generally had stable outage frequency and duration (with major storms excluded). In a 2016 staff report analyzing the customer service PIMs, staff concluded:

> With one exception…the electric and gas utilities' performance on measures of customer service quality in 2015 was satisfactory. The [customer service PIMs] currently in place at the utilities in New York State establish strong standards for performance and put significant amounts of shareholder earnings at risk for nonperformance. Overall, these mechanisms have been effective in encouraging companies to make customer service a corporate priority and providing criteria for ensuring that the quality of customer service remains at satisfactory levels.[138]

In spite of these successes there have been some concerns about the utilities' reliability performance. For example, Consolidated Edison was the subject of a 2006–2007 investigation about reliability due in part to complaints by the legislature. Superstorm Sandy had impacts that were particularly severe, leading the Moreland Commission to conclude in its final report that the utilities had not done enough to effectively respond to severe storms.[139]

6.4 MidAmerican Energy

MidAmerican Energy is a VIEU based in Des Moines that provides electric service in most of Iowa and portions of two adjacent states. The company operated under a sequence of MRPs without intervening rate cases for more than a decade through a series of settlements approved by the Iowa Utilities Board. The settlements had many common features, including rate freezes that extended to charges for energy procured.

Plan Designs

MidAmerican's first MRP began with a 1997 general rate case settlement that featured a three-and-a-half-year rate case stayout.[140] Residential rates were reduced in two steps at the outset. Rates for commercial and industrial customers were not directly reduced. Instead, amounts allocated for these reductions were to be used to fund negotiated contracts with customers or unbundled pricing retail access pilots. The energy adjustment clause was eliminated, exposing the company to fluctuations in prices of energy commodities but permitting it to benefit if high prices in bulk power markets bolstered margins from sales in these markets. A capital cost tracker was included in the plan to address costs of plant additions at the Cooper Nuclear Station. An earnings sharing mechanism (ESM) refunded a share of any earnings surpluses to customers.[141] An off-ramp was included to allow rate cases in the event that earnings were excessively low or high. Iowa law required utilities to offer DSM programs. Costs of these programs were tracked, but no DSM PIMs were approved. Service quality monitoring was instituted in the early 2000s through a change to the state's administrative code.

This plan also allowed MidAmerican to utilize additional marketing flexibility through waivers of existing flexible pricing rules. The company could provide discounts based on the cost to serve individual customers without being required to offer the same discount to all competing customers. The pricing floor

[138] New York State Department of Public Service (2016), pp. 13–14.
[139] Moreland Commission (2013b).
[140] Iowa Utilities Board (1997).
[141] The term revenue sharing is often used instead of earnings sharing in Iowa.

was set at the short-run marginal cost of serving that customer. Contracts in excess of five years were permitted.

Subsequently, approved settlements made small changes to the framework but continued the rate case stayout.[142] The customers' share from the earnings sharing mechanism was redirected into a source of funding for new plants. The capital tracker for Cooper plant additions expired.

Through separate legislation, Iowa electric utilities, including MidAmerican, gained unusual certainty with regard to future ratemaking treatment of generating plant additions. Instead of cost trackers, this certainty has been in the form of ratemaking principles to be applied to new facilities when they are added to the utility's rate base. These principles may include a prudence decision up to a cost cap, the allocation of plant costs to Iowa ratepayers, allowed ROE for the life of the plant, and plant service life.

Throughout the 1997–2013 period, MidAmerican's tariffed base rates did not increase. For residential customers, they decreased by $15 million. The company was nevertheless able to handle effects of several severe weather events and environmental compliance while building a coal-fired generating unit, a gas-fired combined cycle plant, and more than 1,800 MW of wind generation. These assets were added to the utility's rate base years after they entered service, which allowed them to be added at less than their gross plant value due to depreciation. The customer share of earnings yielded by the ESM-funded accelerated depreciation of the coal-fired Walter Scott, Jr. Energy Center Unit 4 exceeded $300 million.[143]

Surplus earnings were aided by bulk power market sales margins. In 2003 testimony, a MidAmerican witness stated:

> In Iowa rate cases prior to the adoption of revenue sharing in 1997, the appropriate treatment of wholesale margins was a contested issue. Since the adoption of revenue sharing, these margins have been shared with retail customers. In fact, since revenues from Iowa retail operations have consistently produced returns below 12% [the threshold for revenue sharing], the revenue sharing mechanism has essentially been a mechanism for sharing these wholesale margins with retail customers.[144]

Declines in bulk power market prices after 2007 helped trigger an off-ramp that resulted in a cost tracker being added to the plan. Other stresses identified by the company in requesting a tracker included environmental, coal and coal transportation costs. The company filed a full rate case in 2013, resulting in a new MRP that phased in a $135 million base rate increase over three years. This MRP also reinstituted an energy adjustment clause. Variances from test year revenue levels resulting from sales for resale continue to be shared solely through the ESM.

Outcomes

Cost Performance

The infrequency of rate cases and the unlikely ability of poorly managed distributor costs to trigger rate cases gave MidAmerican incentive to contain distributor costs that approached those in competitive markets. Table 7 and Figure 9 compare the power distributor productivity growth of MidAmerican to averages for our full U.S. electric utility sample. From 1980 to 1995, before the start of MRPs,

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142 Iowa Utilities Board (2001; 2003).
143 Fehrman (2012), p. 3.
144 Gale (2003), pp. 24–25.

MidAmerican's power distributor MFP growth fell by 1.37 percent annually. This was 190 basis points below the MFP growth trend of sampled power distributors nationally. Over the 17-year period over which MidAmerican Energy operated without a rate case (1997–2013), the MFP of its power distributor services averaged 1.16 percent annual growth. That compares to the 0.42 percent trend for our full sample of U.S. power distributors during the same period. The MFP growth differential therefore averaged 74 basis points in the years of the MRPs. The capital productivity growth of MidAmerican was especially rapid.

Service Quality

In 2015, staff of the Iowa Utilities Board performed a review of reliability performance of the state's two large investor-owned electric utilities. It found that between 2002 and 2014, reliability metrics for both companies were stable. This report also showed that MidAmerican's budgeted transmission and distribution expenses had risen between 2002 and 2005, plateaued until 2008, and fell off for 2009, 2010 and 2011, coinciding with dropping bulk power prices.

DSM Programs

In the eight years for which data were available since 2006, Iowa has averaged a 10.25 average ranking (out of 50) in ACEEE's scorecard on the percent of electric revenues devoted to energy efficiency spending.

Table 7. How the Power Distributor MFP Growth of MidAmerican Energy Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	MidAmerican Energy			U.S. Sample Average		
	MFP	O&M PFP	Capital PFP	MFP	O&M PFP	Capital PFP
1980	-1.93%	-4.26%	-0.78%	-0.49%	-4.19%	1.24%
1981	-2.73%	-5.09%	-1.58%	0.17%	-2.42%	1.25%
1982	-0.58%	3.85%	-2.54%	0.87%	-1.20%	1.53%
1983	1.20%	0.45%	1.46%	0.51%	-0.38%	0.98%
1984	1.89%	1.51%	2.00%	1.27%	-0.22%	1.79%
1985	-0.91%	2.81%	-1.80%	0.95%	-0.21%	1.37%
1986	-0.31%	-2.19%	0.11%	0.91%	0.88%	0.97%
1987	-3.56%	-4.46%	-3.35%	0.44%	-0.12%	0.68%
1988	-1.58%	-1.40%	-1.63%	0.57%	1.55%	0.24%
1989	-2.83%	-5.80%	-1.94%	0.26%	0.00%	0.23%
1990	-1.73%	-1.63%	-1.76%	0.18%	0.64%	-0.05%
1991	-1.82%	0.89%	-2.71%	-0.03%	0.58%	-0.32%
1992	-2.57%	1.99%	-3.92%	0.48%	1.61%	0.10%
1993	-0.02%	2.36%	-0.70%	0.45%	1.19%	0.12%
1994	-0.03%	1.26%	-0.40%	0.94%	2.44%	0.29%
1995	-4.42%	2.64%	-6.55%	0.94%	3.58%	-0.04%
1996	-0.19%	2.55%	-0.99%	0.11%	0.67%	-0.13%
1997	-0.06%	-3.21%	0.84%	1.53%	4.68%	0.39%
1998	-0.44%	-6.77%	1.45%	0.67%	0.73%	0.71%
1999	1.20%	3.47%	0.54%	1.08%	2.24%	0.52%
2000	1.97%	-1.61%	3.04%	0.89%	0.86%	0.73%
2001	-0.02%	-3.98%	1.30%	1.20%	2.73%	0.61%
2002	1.15%	3.17%	0.43%	0.79%	2.73%	0.33%
2003	0.48%	-1.19%	1.10%	-0.03%	-1.50%	0.43%
2004	1.15%	-1.15%	2.13%	0.41%	0.76%	0.22%
2005	0.58%	-0.01%	0.88%	-0.07%	-0.25%	0.09%
2006	1.27%	2.15%	0.72%	-0.52%	-1.07%	-0.21%
2007	-0.42%	-3.61%	2.59%	-0.12%	0.00%	-0.02%
2008	0.85%	1.50%	-0.27%	-0.99%	-2.06%	-0.09%
2009	6.10%	9.84%	0.58%	1.01%	2.73%	-0.46%
2010	2.00%	1.35%	2.48%	-0.27%	-0.47%	0.05%
2011	1.99%	3.30%	1.21%	0.50%	0.05%	0.50%
2012	2.54%	3.77%	1.87%	1.29%	2.90%	0.58%
2013	0.75%	-2.73%	2.42%	0.03%	0.40%	-0.05%
2014	2.32%	1.20%	2.85%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.04%**	**0.03%**	**-0.03%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**-1.37%**	**-0.44%**	**-1.63%**	**0.53%**	**0.23%**	**0.65%**
1997-2013	**1.16%**	**0.38%**	**1.24%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**2.37%**	**2.61%**	**1.59%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

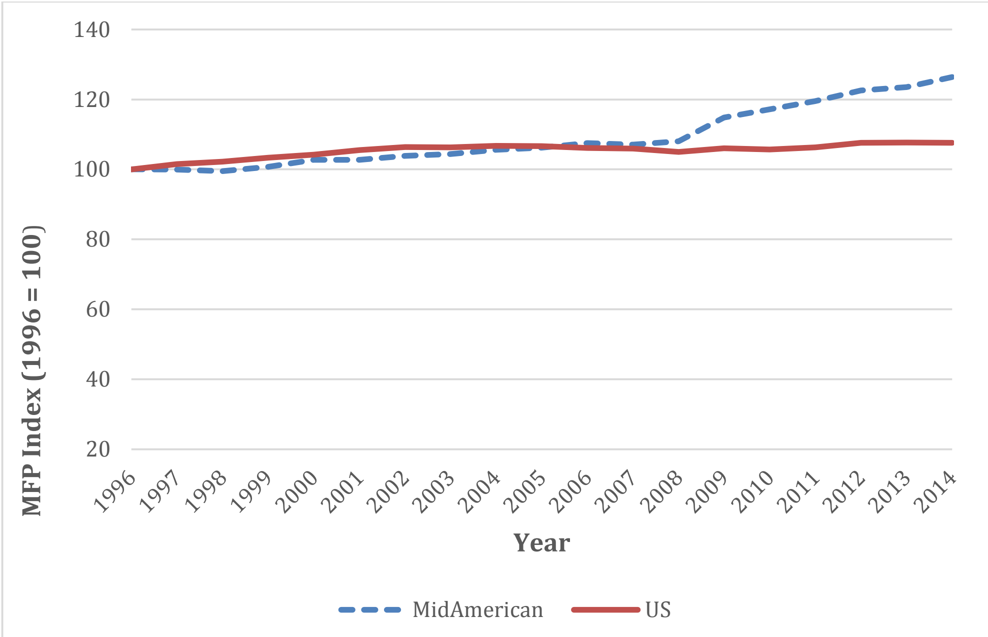

Figure 9. Comparison of Multifactor Productivity Trends of MidAmerican Energy and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of MidAmerican exceeded the industry norm under its MRPs.

6.5 Other U.S. Electric Utilities With Extended Rate Stayouts

We noted above that many U.S. electric utilities have avoided general rate cases for lengthy periods. These utilities have been able to operate without rate cases for various reasons. In some cases, utility costs were likely to grow slowly due, for example, to recent completion of one or more large generating stations. Some utilities were able to slow cost growth with mergers or acquisitions. Others may have started their stayout periods with favorable initial rates due to high allowed rates of return. Some operated under an MRP for part of the period or a rate freeze during transition to retail power market competition and were not required to file a rate case upon their conclusion.

Table 8 identifies U.S. electric utilities in our sample that have experienced rate stayouts exceeding 12 years since 1980. About half of these utilities were vertically integrated throughout the sample period. Others started as VIEUs but restructured during the period.

We calculated productivity trends of these utilities as power distributors during the years of their rate stayouts and compared these trends to average annual productivity growth rates of our full U.S. sample during the same years. Table 8 presents results. We found that multifactor productivity growth of utilities during extended rate stayouts exceeded that of the full U.S. sample during the same period by 29 basis points on average. Operation and maintenance and capital productivity growth were both superior. During other years of the full 1980–2014 sample period, MFP growth of these utilities exceeded MFP growth of the full U.S. sample by less than a basis point on average. This evidence suggests that extended rate stayouts lowered distributor costs.

Table 8. Difference Between Company and U.S. Power Distributor MFP Trends During Extended Stayout Periods

	Stayout Period			Stayout Period MFP Trend			Stayout Period O&M PFP Trend			Stayout Period Capital PFP Trend		
Company	Start	End	Duration*	Company	US Sample	Difference	Company	US Sample	Difference	Company	US Sample	Difference
Baltimore Gas and Electric Company	1993	2010	18	0.30%	0.45%	-0.15%	1.42%	1.11%	0.31%	-0.02%	0.20%	-0.21%
Dayton Power and Light Company	1992	2014	23	0.49%	0.45%	0.04%	1.76%	1.02%	0.74%	0.07%	0.23%	-0.15%
Duke Energy Carolinas, LLC	1991	2007	17	0.65%	0.51%	0.14%	2.91%	1.29%	1.62%	-0.10%	0.22%	-0.32%
Duke Energy Progress, LLC	1988	2012	25	0.64%	0.45%	0.19%	2.42%	1.09%	1.32%	-0.10%	0.19%	-0.29%
Duquesne Light Company	1988	2006	19	1.04%	0.52%	0.53%	1.61%	1.27%	0.34%	0.96%	0.22%	0.74%
El Paso Electric Company	1995	2009	15	0.76%	0.46%	0.30%	2.58%	1.12%	1.46%	-0.82%	0.20%	-1.02%
Fitchburg Gas and Electric Light Company	1985	1999	15	-0.35%	0.63%	-0.98%	0.10%	1.36%	-1.27%	-0.30%	0.34%	-0.64%
Florida Power & Light Company	1984	2001	18	0.99%	0.71%	0.27%	2.78%	1.32%	1.46%	0.24%	0.46%	-0.22%
Indiana Michigan Power Company	1993	2007	15	0.41%	0.55%	-0.14%	1.41%	1.32%	0.09%	-0.09%	0.27%	-0.36%
Indianapolis Power & Light Company	1995	2014	20	0.97%	0.42%	0.55%	1.38%	0.91%	0.47%	0.85%	0.24%	0.62%
Kentucky Power Company	1991	2005	15	0.41%	0.62%	-0.22%	1.28%	1.54%	-0.25%	-0.06%	0.27%	-0.33%
Kentucky Utilities Company	1983	1999	17	0.61%	0.66%	-0.05%	0.37%	1.17%	-0.80%	0.62%	0.46%	0.16%
Kingsport Power Company	1992	2014	23	0.26%	0.45%	-0.19%	0.70%	1.02%	-0.32%	0.19%	0.23%	-0.04%
Massachusetts Electric Company	1995	2009	15	1.27%	0.46%	0.81%	1.93%	1.12%	0.81%	0.75%	0.20%	0.54%
Metropolitan Edison Company	1993	2006	14	1.61%	0.60%	1.01%	1.88%	1.41%	0.47%	1.51%	0.29%	1.22%
ALLETE (Minnesota Power)	1994	2008	15	1.50%	0.46%	1.04%	1.23%	1.10%	0.13%	1.61%	0.25%	1.35%
MDU Resources Group, Inc.	1987	2001	15	1.13%	0.65%	0.49%	1.07%	1.56%	-0.49%	1.15%	0.27%	0.88%
Niagara Mohawk Power Corporation	1995	2009	15	1.64%	0.46%	1.18%	3.03%	1.12%	1.91%	0.35%	0.20%	0.14%
Nstar Electric	1992	2005	14	0.15%	0.67%	-0.52%	0.92%	1.61%	-0.69%	-0.26%	0.31%	-0.57%
Ohio Edison Company	1990	2007	18	1.23%	0.49%	0.74%	1.24%	1.26%	-0.02%	1.19%	0.21%	0.99%
Ohio Power Company	1995	2011	17	0.46%	0.42%	0.04%	1.43%	0.96%	0.47%	0.13%	0.21%	-0.09%
Otter Tail Corporation	1993	2007	15	0.02%	0.55%	-0.53%	-0.36%	1.32%	-1.68%	0.40%	0.27%	0.14%
PECO Energy Company	1990	2010	21	0.91%	0.41%	0.50%	1.19%	1.09%	0.10%	0.74%	0.16%	0.58%
Pennsylvania Electric Company	1984	2006	23	0.82%	0.58%	0.23%	1.32%	1.07%	0.25%	0.64%	0.39%	0.24%
Pennsylvania Power Company	1988	2014	27	0.62%	0.42%	0.20%	1.31%	0.97%	0.33%	0.35%	0.20%	0.15%
Potomac Edison	1994	2010	17	1.71%	0.45%	1.27%	2.24%	1.11%	1.14%	1.48%	0.20%	1.28%
Tampa Electric Company	1993	2008	16	0.95%	0.46%	0.50%	1.67%	1.11%	0.56%	0.75%	0.25%	0.51%
Duke Energy Kentucky, Inc.	1992	2006	15	0.84%	0.59%	0.25%	2.99%	1.43%	1.56%	0.01%	0.28%	-0.27%
West Penn Power Company	1995	2014	20	1.29%	0.42%	0.86%	2.49%	0.91%	1.58%	0.84%	0.24%	0.60%
Averages												
Stayout Period Average				**0.80%**	**0.52%**	**0.29%**	**1.60%**	**1.20%**	**0.40%**	**0.45%**	**0.26%**	**0.19%**

* Period is inclusive of both endpoints. End dates in January and start dates in December were assigned values one year earlier and later respectively.

6.6 Statistical Tests of Productivity Impacts

The productivity growth rates of individual utilities are quite volatile from year to year. Differences between the annual productivity growth rates of utilities operating under MRPs and annual full sample growth rates may therefore not reflect the impact of the plans. A statistical technique called *hypothesis testing* can be used to infer whether a utility's productivity growth is impacted by an MRP or, if instead, the observed difference between the productivity trends of individual utilities operating under MRPs and the full sample is a coincidence caused by volatility. We conducted hypothesis tests, called *T-tests,* to evaluate whether the average productivity trend of a utility under an MRP or stay out was significantly greater than the productivity trend of the full sample during the same years.

The first T-test was applied to observations of the differences in the MFP trends between utilities operating under a stay out and the full sample during the stay out period. The null hypothesis was that the difference in productivity trends is equal to zero. The alternative hypothesis is that the difference is greater than zero or, on average, utilities operating under a stayout have higher productivity trends than the full U.S. sample during the stayout period. The sample (N=29) consists of the number of "stayout utilities" in Table 8. The mean difference in the productivity trend is .29 percent, and the standard deviation is .53 percent. The t-statistic for this sample is 2.914, which is greater than the 5 percent one-sided critical value of 1.701. Thus, we can reject the null hypothesis in favor of the alternative hypothesis that companies operating under a stayout have a higher productivity trend during the stayout period than the full sample.

A second T-test was applied to observations of the differences between the productivity trends of utilities operating under formal MRPs as well as stayouts and the trend for the full sample in the same years. The null and alternative hypothesizes were the same as in the first test. The sample (N=40) consists of the utilities in the first test plus the California and New York utilities that have operated under an MRP, MidAmerican Energy, and Central Maine Power. The mean difference in the productivity trend is .22 percent and the standard deviation is .61 percent. The t-statistic for this sample is 2.224, which is greater than the 5 percent one-sided critical value of 1.683. Thus, we can again reject the null hypothesis in favor of the alternative hypothesis. The average difference in the productivity trend of .22 percent is half of the productivity trend of the full sample over the 1980–2014 time period, suggesting that MRPs have an economically significant effect on utility operations.

6.7 PBR for Ontario Electric Utilities

The Ontario Energy Board has emerged in recent years as a top practitioner of PBR.[145] The event that drove innovation was the transfer of responsibility to the Board in the late 1990s to regulate more than 200 provincial power distributors. In addition to power distributors, the Board regulates large provincially owned transmission and generation companies and two large gas utilities.

Power distributors regulated by the Board are remarkably varied. Hydro One, which provides most transmission services in Ontario, also provides distribution services to many towns and unincorporated areas. In addition, large distributors serve Ottawa and Toronto. Most other distributors serve small towns, suburbs or rural areas of the province, and some have just a few hundred or thousand customers. Many of these distributors are municipally owned while the largest, Hydro One Networks, is provincially owned.

[145] PEG Research has advised the Board on PBR for many years, performing several productivity and benchmarking studies.

Despite long experience with cost of service regulation (for gas utilities), the Board opted to use MRPs in power distributor regulation.[146] The Board stated in a draft policy decision three reasons why use of PBR would be helpful in electric utility regulation:

1. With passage of [a bill restructuring the electricity industry], the Board will have the task of regulating a large number of diverse utilities in the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstances change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

2. PBR would allow the Board to establish minimum service quality and reliability standards and maintain compliance with these standards.

3. PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of consumers.[147]

The Board has since approved a sequence of multiyear rate plans. PBR is called *incentive regulation* (IR) and rate plans are called *incentive regulation mechanisms* (IRMs). The first plan (IRM1) began in 2001. The Board extended this plan to March 2005 to allow utilities additional time to “explore the incentives for improvements and savings provided by the current PBR regime.” However, IRM1 was suspended well before its termination date as a result of price spikes in Ontario’s new bulk power market. Bill 210, enacted in December 2002, froze existing rates until May 2006 unless approval was otherwise granted by the Minister of Energy.[148]

Rates were adjusted in May 2006 based on rate cases filed in 2005. Between 1999 and May 2006, distributors therefore operated without rate cases and received only one or two modest base rate increases. During this period, utilities had strong incentives to contain costs, and some utilities may have deferred some expenditures.

IRM2 used the May 2006 rates as a starting point. Roughly a third of all distributors were then scheduled for rate cases in each year of the 2008–2010 period. After these rate cases (called *rebasings*), distributors switched over to IRM3. Terms of these plans were initially fixed at three years plus a rebasing year. This was later extended, resulting in plans for some companies lasting five years. Extension was partly based on the Board’s in-depth reexamination of its ratemaking practices, called “A Renewed Regulatory Framework for Electricity,” which began in 2010. A fourth generation IRM and some optional alternative MRP approaches resulted from these deliberations.

Plan Design

Attrition Relief Mechanism

All four IRMs featured indexed price caps. Macroeconomic inflation measures have been used in some plans and industry-specific measures in others. X factors have commonly had two components: a productivity factor reflecting the MFP trend of a peer group and a stretch factor. The peer groups in first and fourth generation IRMs were broad samples of Ontario power distributors, whereas the peer group in the third generation IRM was a broad sample of U.S distributors.

[146] The Board has subsequently embraced MRPs for regulation of provincial gas distributors.
[147] Ontario Energy Board (1998), p. 3.
[148] Legislative Assembly of Ontario (2002).

Stretch factors in third and fourth generation IRMs have varied between utilities based on results of statistical benchmarking studies commissioned by the Board. The benchmarking study in the fourth generation PBR uses an econometric model of total cost and is updated annually. Details of this benchmarking methodology are discussed in Appendix B.3.

Capital Cost Trackers

Capital cost treatments have evolved over Ontario's four IRMs. Supplemental revenue for capex was not available in the first IRM. A separate Ontario policy led to the use of trackers to finance costs of AMI deployment. In the proceeding to approve IRM2, distributors requested supplemental revenue for capex. This request was rejected due to a lack of perceived need, but distributors claiming a need for high capex were permitted to file a rate case early. The Board expressed concerns about special treatments of capital in its decision:

> In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[149]

During the proceeding that led to IRM3, a number of utilities again argued that an indexed price cap would not fund their special capex needs. The Board responded by adding to the plans an Incremental Capital Module that could provide distributors with supplemental capex funding. The Board described this as "reserved for…circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[150] The eligibility criteria for supplemental capex funding subsequently evolved but have consistently required that the capex funded by an Incremental Capital Module not be recoverable in rates, be prudent and the distributors' most cost-effective option, and exceed a materiality threshold. An eligibility formula ensures that forecasted total capex exceeds funding expected from depreciation and higher revenue from price cap index escalation and growth in billing determinants by a certain percentage (currently 10 percent).

Distributors are required to report their actual capex annually. Variances between forecasted and actual capex are reviewed by the Board to determine whether they are material enough to warrant a true-up in a subsequent rate case. Cost overruns are reviewed for prudence, while material underspends result in refunds to ratepayers.

Around 15 of approximately 70 Ontario power distributors have received approval for revenue from Incremental Capital Modules. These modules are typically used to address costs of large capital projects. About two-thirds of applications filed under the program included transformer-related assets as the focal point of the funding request.[151]

In 2014 the Board made "Advanced" Capital Modules rather than Incremental Capital Modules the major source of supplemental capital revenue in IRMs. Utilities must apply in advance, at the time of their rate cases, for supplemental funding of projects that are detailed in five-year Distribution System Plans. Reviews of Advanced Capital Module requests thus coincide with a review of projects proposed in Distribution System Plans, allowing for greater regulatory efficiency. An Incremental Capital Module

[149] Ontario Energy Board (2006), p. 37.
[150] Ontario Energy Board (2008), p. 31.
[151] Ontario Energy Board (2014), p. 7.

remains available for projects not included in a Distribution System Plan, as well as for projects that are in the plan whose eligibility for supplemental funding could not be determined in the rate case, or projects that expand after the plan is presented.

Other Plan Provisions

Terms of incentive regulation mechanisms in Ontario have varied over the years but have typically been four or five years. Reliability PIMs have never been used in Ontario power distributor regulation. However, reliability metrics and targets have been used routinely since IRM1.

Demand-side management PIMs and LRAMs have been offered as an incentive for distributors' DSM programs. A third-party administrator also offers DSM programs.

An earnings sharing mechanism to address overearnings was established for IRM1 but was abandoned in later plans. Some Custom IR plans include such a mechanism where distributor underspending is a concern.

New Plan Options

The Renewed Regulatory Framework deliberations resulted in two additional options to address the diversity of Ontario distributors.

- Custom IR is designed for distributors expecting several years of high capex. ARMs are based on forecasts of O&M and capital cost. Forecasts should be informed by Board-sponsored productivity and benchmarking analyses. Distributors operating with a Custom IR plan do not have the option to request supplemental capital funding. Custom IR plans have recently been granted to several of the larger distributors.

- The Annual IR index is designed for distributors that do not expect to undertake large capital projects. This option features a price cap index with an inflation — X formula, but the X factor is fixed to reflect the high end of the stretch factor range in IRM4 for all plan years. Utilities that choose the Annual IR index cannot obtain supplemental capital funding. The term of a plan with an Annual IR index is not fixed. The availability to distributors of IRM4 and the Annual IR index is a good example of the use of menus in MRP design.

Scorecards

Part of the implementation of the Renewed Regulatory Framework has been the development of a performance scorecard for Ontario distributors. The scorecard includes data on a distributor's cost, earnings, customer service quality, reliability, DSM and safety performance.

Figure 10 provides an example of a scorecard which was posted on the website of the Board.[152] Cost performance is addressed by two unit cost metrics and the outcome of the econometric benchmarking study that the Board updates annually. Financial metrics include a comparison of the company's ROE to its regulated targets. There are also metrics for less traditional areas, such as peak load management and the quality of service to renewable generation customers.

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[152] Scorecard - Hydro Ottawa Limited (2015), http://www.ontarioenergyboard.ca/documents/scorecard/2014/Scorecard%20-%20Hydro%20Ottawa%20Limited.pdf.

Results are presented in a manner that informs the reader of the utility's performance. For example, a company's billing accuracy is presented along with the target. The trend in performance is indicated for several metrics.

Outcomes

Cost Performance

Table 9 and Figure 11 present productivity trends of Ontario power distributors over the 2003–2011 period. This sample period excludes early years of operation under MRPs in Ontario, including the years of the rate freeze. Some distributors in the sample period we consider may have been catching up on their capex after years of deferrals.

Our results differ from those relied upon by the Board to set X factors in IRM4 because we have changed the output index to rely solely on customers, in order to make results more comparable to those from our U.S. productivity research for Berkeley Lab.[153] We have removed

2012 from our calculations due to concerns about cost data for that year.[154] Note also that the sample excludes Ontario's two largest distributors, Hydro One and Toronto Hydro Electric.

The table shows that Ontario distributors' multifactor productivity grew on average by 0.45 percent annually from 2003 to 2011. This exceeded the U.S. trend of -0.01 percent for these years by 4 basis points. O&M productivity averaged 0.76 percent annually while capital productivity growth averaged 0.26 percent annually. The year-by-year results show that O&M, capital and multifactor productivity grew most rapidly during the 2003–2005 period, the last years of the rate freeze. MFP growth then slowed and was negative in two years.

[153] The original results can be found in Kaufmann, Hovde, Kalfayan, and Rebane (2013). Our results were updated using the working papers: http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors.

[154] While data for 2012 are available, use of these data is problematic for several reasons. For example, Ontario distributors were in the process of changing accounting systems from Canadian Generally Accepted Accounting Principles to the International Financial Reporting Standards, likely making data less comparable.

Scorecard - Hydro Ottawa Limited

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Scheduled Appointments Met On Time		100.00%	97.30%	97.40%	97.40%	98.30%	down	90.00%	
		Telephone Calls Answered On Time		82.10%	82.90%	82.50%	82.20%	80.30%	down	65.00%	
	Customer Satisfaction	First Contact Resolution					85.2%	84.1%			
		Billing Accuracy					99.6%	99.61%	flat	98.00%	
		Customer Satisfaction Survey Results					90%	83%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	C	C	C	up		C
		Serious Electrical Incident Index	Number of General Public Incidents	1	0	1	0	1	flat		0
			Rate per 10, 100, 1000 km of line	0.186	0.000	0.178	0.000	0.182	flat		0.076
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.05	2.44	1.31	1.64	1.59	up		at least within 1.05 - 2.44
		Average Number of Times that Power to a Customer is Interrupted		0.77	1.40	1.13	1.36	0.86	up		at least within 0.77 - 1.40
	Asset Management	Distribution System Plan Implementation Progress					105%	94%			
	Cost Control	Efficiency Assessment				3	3	3			
		Total Cost per Customer [1]		$536	$529	$569	$579	$623			
		Total Cost per Km of Line [1]		$29,776	$28,793	$31,107	$33,222	$36,169			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			14.13%	28.85%	45.57%	70.53%	target not met		85.26MW
		Net Cumulative Energy Savings (Percent of target achieved)			37.74%	65.64%	88.69%	110.71%	target met		374.73GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.45	1.43	1.18	1.07	0.86			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.32	1.37	1.64	1.65			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	9.42%	9.42%	9.42%			
			Achieved		7.86%	9.41%	7.80%	8.06%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: up down flat target met target not met

Figure 10. Sample Ontario Performance Metrics Scorecard.

Table 9. Productivity Trends of Ontario Power Distributors: 2003–2011

	Output		Inputs						Productivities					
	Total Customers[1]		Capital[1]		O&M[1]		Multifactor[2]		Capital		O&M		Multifactor	
Year	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth
		[A]		[B]		[C]		[D]		[E = A-B]		[F = A-C]		[G = A-D]
2002	2,528,664		100		100		100.00		100.00		100.00		100.00	
2003	2,590,817	2.43%	101	1.01%	102	1.77%	101.30	1.29%	101.43	1.42%	100.66	0.66%	101.14	1.13%
2004	2,647,118	2.15%	103	1.66%	100	-1.51%	101.79	0.48%	101.92	0.49%	104.41	3.66%	102.84	1.67%
2005	2,703,821	2.12%	104	1.65%	99	-1.14%	102.42	0.61%	102.40	0.47%	107.87	3.26%	104.40	1.51%
2006	2,748,114	1.62%	105	0.80%	101	1.50%	103.51	1.06%	103.25	0.82%	108.01	0.12%	104.99	0.56%
2007	2,781,589	1.21%	108	2.44%	105	3.82%	106.62	2.96%	101.99	-1.23%	105.22	-2.61%	103.17	-1.75%
2008	2,823,654	1.50%	109	1.16%	106	1.67%	108.08	1.36%	102.34	0.34%	105.04	-0.17%	103.28	0.15%
2009	2,849,054	0.90%	109	0.19%	107	0.44%	108.39	0.29%	103.07	0.70%	105.52	0.45%	103.95	0.61%
2010	2,885,251	1.26%	111	1.80%	104	-2.39%	108.61	0.20%	102.52	-0.54%	109.45	3.65%	105.08	1.06%
2011	2,919,186	1.17%	113	1.30%	108	3.28%	110.87	2.06%	102.38	-0.13%	107.16	-2.11%	104.12	-0.89%
Average Annual Growth Rates:														
2003-2011		**1.60%**		**1.33%**		**0.83%**		**1.15%**		**0.26%**		**0.76%**		**0.45%**

Notes:

[1] Data are from PEG Working Papers: Part II - TFP and BM database calculation, filed with PEG's report "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board" on November 21, 2013 (and updated on January 24, 2014).

[2] This is a Törnqvist index using the total cost shares of capital and OM&A as weights.

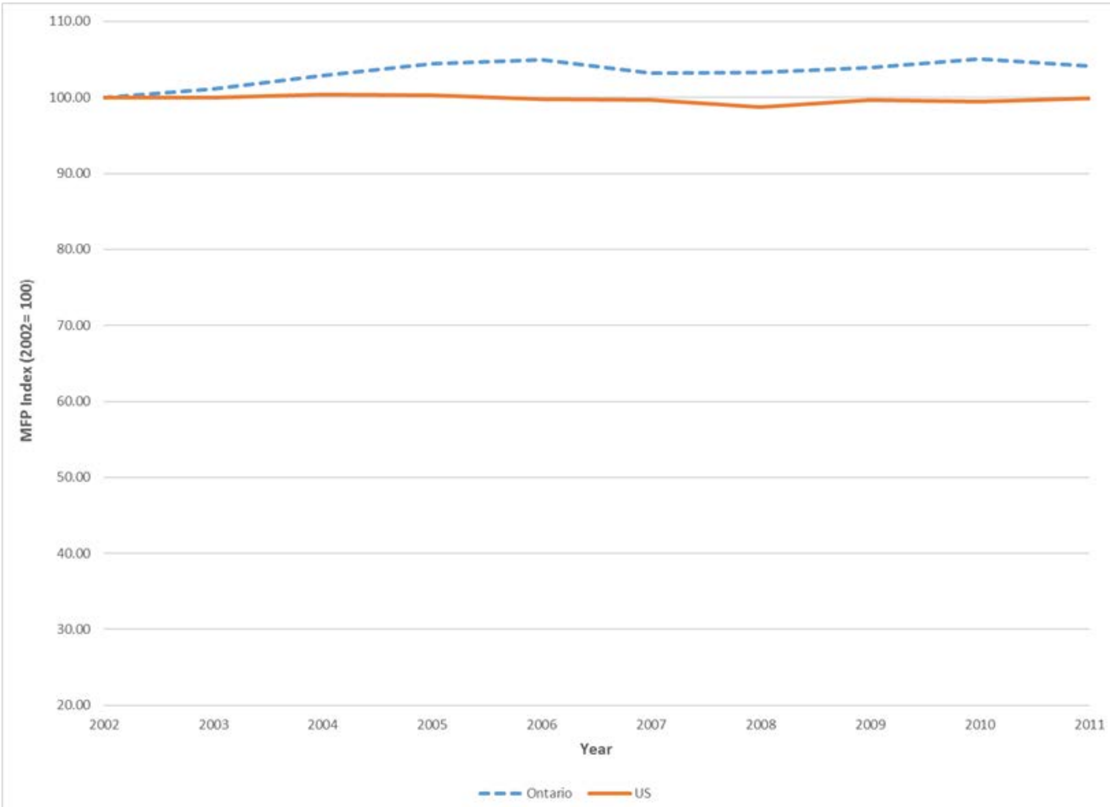

Figure 11. Comparison of Multifactor Productivity Trends of Ontario Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of Ontario distributors exceeded the industry norm under MRPs.

Consolidation

Since the late 1990s, Ontario's power distribution industry has consolidated from more than 200 distributors that existed prior to PBR to about 70 distributors. Hydro One Networks has purchased more than 80 distributors. The Ontario government has noted on several occasions that the industry could become more efficient with greater distributor consolidation. Consolidation may have spurred productivity growth.

Service Quality

Effects of the Ontario MRPs on utility service quality are unclear, potentially a result of data the Board has been gathering. Reported reliability metrics do not exclude major events, leading to potentially large year-to-year variations in performance due to weather events beyond distributors' control. In addition, the period of operation under MRPs (2005–2012) has witnessed the rollout of AMI and SCADA systems. These deployments are often linked to a worsening of measured reliability because more outages are detected by automatic reporting systems.

Some observers have suggested that Ontario distributors had high levels of service quality at the beginning of the MRPs, even to the point of arguing that some utilities had engaged in "gold-plating" their systems. These observers find that during the 2000s, which encompassed IRM1, a rate freeze, and IRM2, reliability suffered.

> [R]eliability has declined continuously from 2000 to 2008; degradation has become progressively worse. Results in the middle years [during the rate freeze] (2003-2005) are significantly worse than the earlier [IRM1] years (2000-2002), and results in the last years (2006-2008) [in which rates were reset and IRM2 was in effect] significantly worse than the middle.[155]

A 2010 Board staff report presented more mixed results:

> The [customer] surveys indicate that the majority of consumers are generally satisfied with current levels of system reliability, with 89% of residential consumers and 92% of business consumers reporting that they are "somewhat satisfied" or "very satisfied" with the reliability of electricity supply. However, over 75% of respondents in both groups indicated that, despite being generally satisfied, they still believe it is important for distributors to continue to work to reduce the number of outages…. There was a strong consensus amongst many participants that the Board should focus on ensuring that system reliability levels are maintained. These participants believe that the current regime is adequate for the purposes of ensuring continued sustainability and reliability…. Ratepayer groups that supported the development of a new reliability regime were in the minority. Some ratepayer representatives suggested that reliability has declined almost continually over the last 8 years.[156]

6.8 Power Distribution MRPs in Great Britain[157]

The power distribution industry of Great Britain also has a history very different from that of the United States. Until 1990, British electric utilities were not investor-owned. In the intervening years, these utilities have been privatized and restructured into separate generation, transmission and distribution operations. End users are billed by retailers, not distributors. This arrangement reduces the role of distributors in provision of DSM programs. Regulatory requirements of British utilities are codified in their licenses, rather than tariffs, administrative codes or laws.

There are currently 14 power distributors, eight gas distributors, three electric transmitters and one gas transmitter in Britain. The sizable task of regulating these utilities has been assigned to the Office of Gas and Electricity Markets (Ofgem). Ofgem also regulates gas and electric commodity markets.

155 Cronin and Motluk (2011).
156 Ontario Energy Board (2010), p. 7–10.
157 A 2016 Berkeley Lab report (Lowry and Woolf) discussed the British system of energy utility regulation. This section provides additional history and plan design details and discusses notable outcomes.

Since privatization, British energy utilities have operated under a sequence of MRPs called *price controls.* The British approach to price controls has its roots in a 1983 document by British economist Stephen Littlechild, which relied on five criteria to evaluate regulatory options:[158]

- protect against monopoly power
- encourage efficiency and innovation
- minimize regulatory cost
- promote competition
- maximize proceeds from privatization

Traditional cost of service regulation was rejected by policymakers after scoring poorly on four of the five criteria. The one criteria where cost of service regulation performed well was protecting against monopoly power.

Littlechild proposed to regulate rate growth with an index using an inflation – X formula. Regulators have refined various features of the plans over the years in their periodic price control reviews. To date there have been five completed generations of price controls, with the sixth price control beginning in 2015. Ofgem undertook a substantial review of its regulatory practices beginning in 2008. The revised regulatory system that resulted from these deliberations is called *RIIO* (Revenues = Incentives + Innovation + Outputs).

Plan Design

Plan Term

British MRPs have traditionally had five-year terms. With the adoption of RIIO, the term of plans was extended to eight years. This strengthens performance incentives but has complicated the task of developing and reviewing plans.

Attrition Relief Mechanism

Price controls for power distributors in Britain originally featured price caps but now feature revenue caps. Caps of both kinds have been escalated by hybrid methods. Allowed revenue trajectories are established based on multiyear total cost forecasts. Principal components are forecasts of the value of the current capital stock and of capital spending, depreciation, the return on capital, and O&M spending. Because of the focus on component costs, the British approach to ARM design is sometimes called the *building block* method.

Britain's Retail Price Index (RPI) has been used as the inflation measure of the revenue cap indexes. Given forecasts of total cost, billing determinants and inflation, past plans have selected combinations of initial rates and an X factor such that forecasted revenue equals forecasted cost. The revenue cap escalator in RIIO has an implicit X factor of zero.

Use of forecasts to establish allowed revenue led to concerns by Ofgem and its predecessor, the Office of Electricity Regulation, about utility exaggerations of capex requirements. For example, underspends occurred in a period when utilities had forecasted high capex due to an "echo effect" when facilities installed in a past capex surge approached the end of their service lives. In its 1994–1995 price control review, the regulator accepted the need for a high level of replacement capex, noting that facilities from a

[158] Littlechild (1983). Littlechild subsequently served as director general of the electricity regulator.

prior capex surge were approaching retirement age. The regulator nonetheless reduced individual company total capex proposals by as much as 25 percent because not all of the capex was deemed necessary.

In its next price control review, the agency compared distributors' actual capex during the expiring price control to the budgets that had been approved. Figure 12 shows that actual capex was lower than the regulator's approved levels. The regulator came to the conclusion that the "echo effect" was less pronounced than it had expected.[159]

The regulator suspected that some utilities had misrepresented their capex needs. This experience encouraged the regulator to consider some implications of extensive capex underspends in developing a new price control.[160] Ofgem began by reassessing its policy on underspending:

> Ofgem would expect such companies to retain the benefit of their under-spend. Given that, to a significant extent, the nature and timing of capital expenditure (particularly non-load related expenditure) is discretionary, measures need to be introduced to ensure that companies are only rewarded for genuine efficiency not timing benefits obtained through manipulation of the periodic regulatory process.
>
> In this context, it is particularly important to ensure that companies do not have a perverse incentive to 'achieve' periodic delays in capital expenditure, such that they regularly under-spend Ofgem's forecasts, thereby gaining a financial benefit, and then claim a higher allowance for the subsequent period in respect of the capital expenditure which has not been undertaken.… Further where [distributors] underspend in one period and then forecast an increase in expenditure in the next, this will be carefully scrutinized.[161]

The regulator further stated that:

> The unavoidable information asymmetry between regulator and regulated companies is a major issue especially since, under the present regime, regulated companies have an incentive to overstate required expenditures when discussing future price controls with the regulator.[162]

[159] Offer (1999), p. 46.
[160] During the course of the proceeding, Offer merged with the British gas regulator Ofgas to become Ofgem.
[161] Ofgem (1999), p. 41.
[162] Ofgem (1999), p. 7.

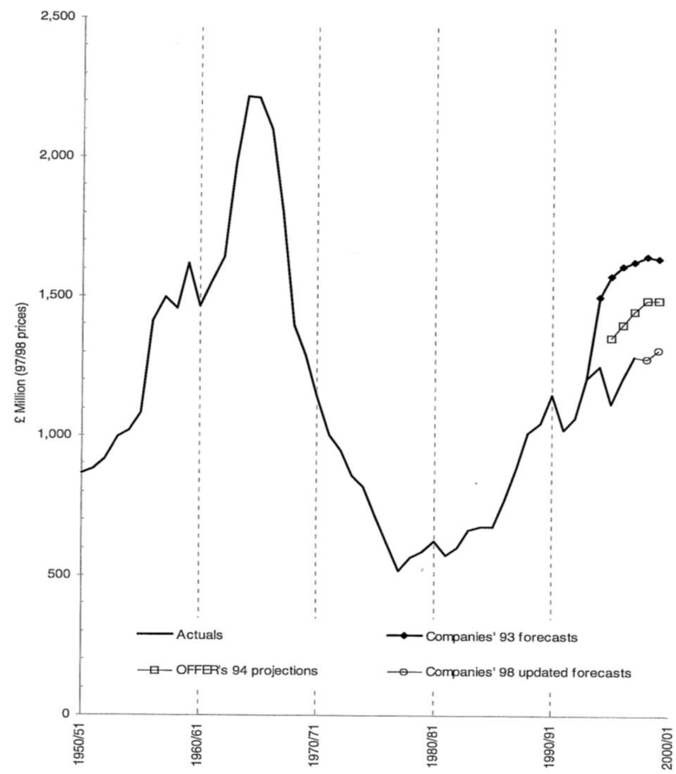

Figure 12. Distribution Business Capital Expenditures (1997/98 Prices). A capex surge during the period 1993–2000 was due to an "echo effect" from a past capex surge that was lower than forecasted.[163]

Ofgem penalized three distributors in its final decision which had provided exaggerated forecasts of capex and operating expenditures (opex). Nevertheless, it became apparent that forecasting overstatements had continued. Ofgem found that capex was being underspent by utilities under the first three years of the new price control.[164] Many power distributors were also providing forecasts describing a need for capex that was more than 20 percent greater than previous forecasts.[165]

Due in part to such experiences, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies to develop its own independent view of required cost growth. In 2004, Ofgem added to rate plans an Information Quality Incentive (IQI) to encourage more accurate capex forecasts. This complicated PIM, an example of an incentive-compatible menu, is discussed further in Appendix A.3.

Distributors that have well-justified business plans at an early stage of the RIIO proceeding can be "fast-tracked." Fast-tracking allows the distributor to receive approval of its business plans as much as a year earlier than would otherwise be the case and avoid more intense scrutiny of its business plan. This enables the distributor a greater opportunity to focus on executing its business plan during the run-up to the new MRP.

Another innovative feature of RIIO is its focus on total expenditures (totex) to level the playing field between capex and opex. Ofgem has explained the rationale for a totex focus:

[163] Offer (1999), p. 45.
[164] Ofgem (2004a).
[165] Ofgem (2004b).

> The incentives to manage different types of costs under the price control are not equal. These imbalances may distort the decisions that [distributors] need to make between capex and opex solutions and create boundary issues. This is not in customers' interests as it may lead to [distributors] seeking to outperform the settlement by favoring capex over opex (or vice versa). This may lead to inefficient network development and higher charges for customers in the short or long term….
>
> These rules create two undesirable effects:
>
> - Incentives are distorted toward adopting capex rather than opex solutions. This means that [distributors] are not incentivized to minimize total lifetime costs as they are sometimes better off by adopting a capex solution rather than a cheaper opex solution due to the way that the different expenditures are treated.
>
> - Boundary issues are created. There is an incentive to record expenditure in the areas with the highest rates of capitalization even if the expenditure was not technically in that area. This requires significant policing of the cost reporting of [distributors].[166]

To address these problems, Ofgem decided to equalize the incentives between opex and capex for most cost categories.[167] Instead of traditional expensing and capitalization rules, Ofgem fixed the amount of total expenditures that could be capitalized at 85 percent. Newly capitalized costs would be recovered over a 45-year period, while existing rate base costs would be recovered over a 20-year period. The remaining 15 percent would be expensed.

Performance Metric System

RIIO features complicated performance metric systems that include several PIMs. Metrics in this system are called *outputs.* The performance incentive mechanisms in RIIO place a sizable share of distributor revenue at risk, prompting some commentators to call RIIO a "results-based" approach to regulation. However, the unusually large sensitivity of earnings to performance mechanisms in RIIO is due mainly to the Information Quality Incentive.

With respect to service quality, Ofgem adopted guaranteed reliability standards early on, later adding guaranteed standards of performance for connections. One example of a guaranteed standard is that distributors are required to restore service within 12 hours in normal weather conditions. Distributors must make predetermined payments directly to customers each time a minimum performance standard is not met. Ofgem also developed a reliability PIM called the *Interruptions Incentive Scheme* that addresses distributors' outage frequency and duration performance.

Ofgem has expanded its customer satisfaction PIM over the years into a Broad Measure of Customer Satisfaction. This encompasses the number of complaints that a distributor has and an assessment of customer satisfaction with distributors' responsiveness with regard to outages, connections and general inquiries. Ofgem has also experimented with PIMs to encourage reductions in line losses.

Distributors are required to report annually on numerous additional metrics. These have expanded over the years from cost and revenue reporting to include measures that are not commonly reported in the United States, including the health of assets, substation utilization levels and air emissions. Business

[166] Ofgem (2010), p. 107.
[167] Costs that were not provided this treatment include many types of administrative and general expenses, pensions and several costs that receive supplemental funding, discussed later in this section.

Carbon Footprint metrics include distributors' annual electricity losses in addition to their direct carbon emissions.

Ofgem reviews distributors' annual reports on these metrics and issues its own report summarizing distributors' performance. Reports feature a scorecard with "traffic lighting," using red to indicate poor performance, green to indicate good performance, and yellow to indicate performance in between.

RIIO also changed asset health metrics into a risk index. The risk index is a composite measure of asset health and criticality indexes, reflecting risks of asset failures for a distributor. The asset health index measures the likelihood of an asset failure, while the criticality index measures the impact of a potential asset failure. The risk index has become the basis for a PIM with a possible penalty or reward of 2.5 percent of avoided or incurred costs.

RIIO has also increased use of discretionary financial incentives. A stakeholder engagement incentive encourages distributors to engage with customers and incorporate their input in decisions and to identify vulnerable customers and take efforts to ensure their energy needs are met. An incentive for connections engagement assesses a distributor's effort in formulating and pursuing strategies for providing and improving connection services to large customers, as well as a distributor's use of information learned from these customers to improve these services. A load index measures substation loading on a distributor's primary network.

Revenue Decoupling

While being described as a "price control," Ofgem today uses revenue caps. A "correction factor" refunds or charges customers for variances between actual and allowed revenue. In past plans, sales volume and customer growth increased the company's allowed and actual revenue to some extent.[168] However, this linkage was eventually eliminated, resulting in revenue decoupling that continues through RIIO today.

Cost Trackers

British MRPs often feature mechanisms similar to cost trackers for various costs that are difficult to control. For example, most pension costs have been tracked. Trackers also have been put in place for an assortment of special projects including load reinforcement, high value projects and rail electrification. Supplemental revenue can only be requested at one or two prespecified periods during the rate plan. Another variant on cost trackers is supplemental allowances that distributors can access for specific projects. These allowances have been developed for various purposes, including improvement in the reliability of service to "worst served customers," workforce renewal, distributor innovation efforts, and to encourage distributors to begin making changes toward a low carbon future.

Outcomes

From 2008–2010, as part of the RPI-X@20 process to modernize its regulatory system, Ofgem undertook an extensive review of effects of its price controls. Reviews are also held at the end of each price control. In these reviews, Ofgem indicated that many MRP features had functioned well. For example, in 2009 the regulator stated:

> We have found that allowed revenue have declined since RPI-X regulation was introduced and we expect network charges to have followed a similar trend. Improvements in operating

[168] The percentage of revenue growth tied to the growth in revenue drivers, including customer and sales growth, was determined for each rate plan.

> efficiency and stability in the allowed cost of capital have facilitated these declines. Capital investment has been increasing and the reliability of the supply to customers has improved. These have all been driven at least partly by the regulatory framework…
>
> Our analysis reveals changes in recent years, however. Allowed revenue has stabilized or increased, reflecting increased investment. Operating efficiency improvements are expected to continue, but the scale may be limited compared to the period since RPI-X regulation...
>
> We have also found evidence that the regulated networks have generally managed to beat the regulatory settlement. Whilst this in itself is not necessarily cause for concern, there are questions about the extent to which companies are able to outperform and whether those companies earning the highest returns are indeed those that perform best for consumers.[169]

Cost Performance

Studies of multifactor productivity trends of British power distributors like those we have undertaken for North American distributors have been hampered by poor data. In particular, a consistent time series dataset is not available for many years, as the definitions of costs have changed over time.[170]

Ofgem commissioned a study of historic and expected productivity trends of British power distributors and the U.K. economy.[171] The study found that from program year 1991–1992 to program year 2001–2002, the British distributors averaged annual MFP growth of 4.3 percent. The opex productivity trend was 7.9 percent while the capital productivity trend was 1.2 percent. These MFP results were substantially higher than those of the U.K. economy as a whole and U.S. power distributors for similar time periods. However, the MFP measurement methodology was different.

In its RPI-X@20 review, Ofgem found that during the course of the price controls, real controllable operating costs per unit of energy distributed declined by 3.1 percent per year.[172] This decline exceeded the targets set by Ofgem in the price control reviews. In addition, distributors often underspent their capex budgets.

A major focus of Ofgem reviews of distributors' performance is comparisons of actual and allowed spending. The regulator found that 12 of 14 distributors had underspent their allowance. Ofgem attributed this outcome to several factors: improvements in efficiency, with unit costs for asset replacement work falling significantly; falling input prices; and a drop in reinforcement, connection and high value projects due to economic conditions. However, distributors had not delivered on their commitments in some areas, such as flood risk reduction programs.[173]

Reliability

The RPI-X@20 review assessed the reliability performance of power distributors under price controls. It found that the frequency and duration of outages had declined about 30 percent between 1990 and 2008. These trends continued, with a further 20 percent reduction in outage frequency and 30 percent reduction in outage duration between program year 2009–2010 and program year 2014–2015.[174]

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[169] Ofgem (2009a), p. 26.
[170] Ofgem (2009e).
[171] Information comparable to what we have gathered on the MFP trends of U.S. power distributors is unavailable.
[172] Real controllable operating costs were defined as operating costs less depreciation and "atypical" items.
[173] Ofgem (2015), p. 22.
[174] Ofgem (2015), p. 45.

RIIO

In February 2017, Ofgem released its first annual report on experience under RIIO.[175] The regulator reported that 12 of 14 distributors were spending less than they were allowed.[176] After the first year, distributors expected to underspend their allowances by 3 percent for the entire term of RIIO.

The report also noted that distributors had managed to over-earn by about 300 basis points on average. Ofgem believed that ROE performance was "predominantly driven by all [distributors] performing well against the Interruptions Incentive Scheme."[177] All distributors earned rewards under the scheme.

Distributors also had strong performances in several other areas:

- All distributors decreased their business carbon footprint and sulfur hexafluoride leaks during the first year of RIIO.
- Distributors also significantly improved their times to quote new connections. The industry average for the first year of RIIO was 46 percent to 49 percent lower than the target.[178]
- No distributors were penalized under the Incentives on Connections Engagement, as Ofgem was pleased with quality and detail of distributors' submissions.

All distributors received awards from the Broad Measure of Customer Service, and only one distributor was penalized as a result of poor customer satisfaction survey score.

[175] Ofgem (2017).
[176] On average, the distributors spent 9 percent less than their allowance for the first year of RIIO. These areas of underspending were partly offset by increased spending on inspections, repairing faults on the networks, and service quality.
[177] Ofgem (2017), p. 13.
[178] Ofgem (2017), p. 33.

7.0 Conclusions

The electric utility industry has played a key role over the years in the high performance of the U.S. economy. The industry was largely built under the cost of service approach to utility regulation. This regulatory system sets base rates in general rate cases at levels that compensate utilities for the costs they incur for capital, labor and materials. The scope of trackers that expedite recovery of utility costs has expanded in some jurisdictions to encompass costs of capital and other base rate inputs, as well as energy.

We have shown in this report that the efficacy of cost of service regulation (COSR) varies with business conditions. When conditions favor utilities, as often was the case in the years when COSR became an American tradition, rate cases are infrequent, performance incentives are strong, and regulatory cost is restrained. When business conditions are unfavorable, utilities file frequent rate cases or seek tracker treatment for more costs, or do both. As a consequence, performance incentives are weaker and regulatory cost is higher.

Multiyear rate plans are a salient alternative to COSR for electric utilities. Extensive experience has accumulated with these plans. Regulators have typically approved MRPs on the grounds that they strengthen performance incentives while reducing regulatory cost. Plans have had diverse provisions, and extensive experimentation has occurred.

MRPs can improve the efficiency of regulation. With less time spent on general rate cases, costs of regulation can be reduced, or resources can be redeployed to other useful activities like rate design and distribution system planning. In principle, MRPs that do not impair utility performance or harm customers could be adopted solely on the basis of better regulatory efficiency.

It is difficult to assess the impacts of MRPs and rate case frequency on utility cost performance. Costs of utilities are, after all, influenced by many other business conditions (e.g., severe storms and system age) as well as by their regulatory system. This report reviewed impacts of regulation on utility cost performance using two analytical tools: numerical incentive power analysis and empirical research on utility productivity trends.

Both lines of research suggest that MRPs (and, more generally, infrequent rate cases) can materially improve utility cost performance. For example, multifactor productivity growth of the U.S. electric, gas and sanitary sector was found to be considerably slower relative to that of the economy in a period of frequent rate cases than it was in periods when rate cases were much less frequent. We also found that the MFP growth of investor-owned electric utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the U.S. electric utility norm. Stronger incentives produced cost savings of 3 percent to 10 percent after 10 years.

Our incentive power research suggests that *modest* steps in the direction of MRPs from traditional regulation produce only modest improvements in utility cost performance. This is also consistent with our empirical research, which showed that the MFP growth of California and New York utilities, which typically operated under conservative MRPs, were similar to or worse than the U.S. electric utility norm on balance. More robust MRPs — such as those with five-year plans, no earnings sharing, efficiency carryover mechanisms, and avoidance of rate cases between plans — can potentially produce larger gains. Recent innovations in MRP design, such as advances in efficiency carryover mechanisms, can increase incentive power.

Our incentive power research and case studies have important implications. First, utility performance and regulatory cost should be on the radar screen of state utility regulators, consumer groups and utility managers. We have shown that key business

conditions facing utilities today are less favorable than in prior periods when COSR worked well. This can lead to increased rate case frequency and expanded use of cost trackers which weaken utility incentives for improved cost performance.

Notwithstanding potential benefits of MRPs, they have not been adopted for energy utilities in most U.S. jurisdictions.[179] Several reasons can be advanced.

- COSR is well established in the United States, and some commissions are accomplished practitioners. When challenges emerge to the continuation of COSR, quick fixes such as revenue decoupling to address problems related to declining average use and expanded use of cost trackers have been more appealing to many regulators than the more extensive changes required to implement MRPs. State regulators also have tended to resist sweeping change in the direction of cost-plus regulation such as formula rate plans.

- Continuing evolution of COSR will slow diffusion of MRPs. For example, capital cost trackers can be incentivized. Use of PIMs to encourage cost-effective use of DERs can be expanded.

- It can be difficult to design MRPs that generate strong utility performance incentives without undue risk and that share benefits of better performance fairly with customers.

- Some adverse conditions (e.g., need for high capex) which give rise to frequent rate cases and expansive cost trackers under COSR have proven challenging to accommodate under MRPs.

- MRPs invite strategic behavior and plan design controversies. The dollars at stake invite stakeholders to energetically defend their positions. In proceedings to approve plans with indexed ARMs, for example, controversy over X factors has been common.

- Transitional regulatory systems that limit risks of bad outcomes from MRPs through such means as earnings sharing mechanisms and relatively short plan terms often do not generate substantially greater performance improvements than traditional COSR.[180]

- Utilities in most states have not proposed MRPs. While this may reflect their perception of the regulatory climate in their jurisdictions, many utilities may believe that they will make more money (or make the same money more easily) from frequent rate cases and more expansive cost trackers than under an MRP.

- Many consumer advocates are unsure of their role in an MRP system of regulation. Under COSR, consumer advocates intervene in each general rate case to reduce the revenue requirement. The substantial long-term cost to customers of slow productivity growth due to COSR is less visible. The lost opportunity for consumer advocates to spend more time on other regulatory issues may also be underappreciated.

- A key advantage of MRPs is the ease with which they can address brisk inflation. However, inflation has been slow in recent years.

- The impetus for PBR in many countries has come more from regulators and other policymakers than it has from utilities. Regulatory commissions in U.S. states typically have a less daunting

[179] For another discussion of why MRPs are not more popular in the United States, see Costello (2016).
[180] These transitional plans may nonetheless be important stepping stones to more effective regulatory systems.

mandate than regulators in other countries, who often have national jurisdictions with numerous utilities. This reduces the appeal of streamlined regulation.

Notwithstanding these considerations, we believe that use of MRPs is likely to increase in electric utility regulation over time.

- Key business conditions that trigger general rate cases are more likely to deteriorate than to improve in coming years. For example, inflation is more likely to rebound than to slow further due, for example, to rising bond yields. Penetration of customer-side DERs is likely to increase.

- Use of MRPs is already growing in the regulation of vertically integrated U.S. electric utilities.

- Continuing innovation in the United States, Canada and other countries will produce better MRP approaches. For example, regulators are becoming more skilled at designing plans for utilities engaged in accelerated grid modernization. Incentive compatible menus and efficiency carryover mechanisms help to ensure customer benefits.

- A growing number of power distributors will complete accelerated modernization programs and enter a period of more routine capex requirements that pose fewer problems for MRP design.

The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay.[181] Evidence gathered for this report suggests that MRPs did not impair reliability, but this evidence was anecdotal. Lack of data is a major barrier to more comprehensive research on reliability and bill impacts.

[181] In addition, more refined statistical tests of the impacts of MRPs can be devised.

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Appendix A. Further Discussion of Multiyear Rate Plan Designs

This appendix discusses some topics in incentive plan design in greater detail. We consider earnings sharing mechanisms (ESMs), Z factors, marketing flexibility and Ofgem's Information Quality Incentive.

A.1 Earnings Sharing Mechanisms

Earnings sharing mechanisms share earnings variances that arise when a utility's return on equity (ROE) deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[182] While some ESMs share both surplus and deficit earnings, others share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Whether or not to add an ESM is one of the more difficult decisions in multiyear rate plan (MRP) design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of current U.S. and Canadian MRPs. On the plus side, an ESM can reduce risks that revenue will deviate substantially from cost. Unusually high or low earnings may be undesirable to the extent that they reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[183] ESM filings can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures such as inflation indexing, Z factors or revenue decoupling.

A.2 Z Factors

A Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings. Many MRPs have explicit eligibility requirements for Z factor events. Here is a typical list of requirements.

<u>Causation</u>: The costs must be clearly outside of the base upon which rates were derived.

<u>Materiality</u>: The costs must have a significant impact on utility finances. Materiality can be measured based on individual events, cumulative impacts of multiple events, or both.

[182] An ESM is therefore sometimes referred to as a "banded ROE."
[183] This problem can be contained by sharing only the utility's earnings surpluses.

Outside of Management Control: The cost must be attributable to events outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

One of the primary rationales for Z factor adjustments is the need to adjust revenue for effects of changes in tax rates and other government policies on the utility's cost. Another rationale for Z factors is to adjust for effects of miscellaneous other external developments on utility costs which are not captured by inflation and X factors. Z factors can potentially reduce operating risk, without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most benefits of MRPs.

A.3 Marketing Flexibility

Need for Flexibility

Regulators have long acknowledged the need to afford utilities some flexibility in fashioning rate and service offerings. A utility's need for marketing flexibility is greater to the extent that demand for its services is complex, changing and elastic (i.e., sensitive) with respect to the terms of services offered. When demand is elastic, rates that are too high produce more bypass of utility services.[184] Demand elasticity is greater when customers have alternative ways to meet their needs which are competitive with respect to cost and quality. Elasticity is also greater for products that are "discretionary" in the sense that they do not address a customer's most basic needs.

While "core" customers have fewer options and lower elasticities of demand for basic services, electric utilities have long relied on marketing flexibility to customize terms of service to large-volume customers. These customers play a larger role in the earnings of VIEUs than they do in the earnings of UDCs. One reason is that UDCs do not profit from sizable sums these customers pay for power supplies. Another is that some of these customers take service at transmission voltage and do not pay for many distribution-level costs. In addition, all types of utilities desire flexibility when marketing underutilized capacity in competitive markets (e.g., leasing land in transmission corridors).[185]

Interest among electric utilities in marketing flexibility is growing as demand for power services is becoming more complex, changeable and sensitive to terms of service that utilities offer. For example, advanced metering infrastructure, other smart grid technologies, distributed storage, and plug-in electric vehicles open the door to a variety of new utility services. Large-load customers have a growing interest in customized green power services to meet corporate goals. Distributed generation and storage pose a growing competitive challenge in some jurisdictions. However, for the foreseeable future regulators will likely control terms of service to distributed generation and storage customers carefully.

Marketing flexibility can also help utilities encourage customers to use their services in less costly ways. For example, AMI makes it more cost-effective to offer time-varying tariffs to

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[184] Uneconomic bypass occurs when a customer would use a system more at a lower rate that still exceeds the cost of service. When uneconomic bypass is reduced, customers make more contributions to fixed costs that lower rates for other customers.
[185] Margins from "other revenues" benefit retail customers by, for example, reducing the retail revenue requirement in rate cases.

residential and small business customers. These tariffs can encourage reduced loads at times when the cost of electricity is especially high and slow the need for costly upgrades for substations and load-following generation capacity.

Flexibility Measures

Marketing flexibility runs the gamut from greater effort by regulators to approve new rates and services by traditional means to "light-handed" regulation and even decontrol of certain utility offerings.[186] Light-handed regulation typically takes the form of expedited approval of new or revised rate and service offerings. These offerings may be subject to further scrutiny at a later date, such as in the next rate case. Pricing floors are often established based on marginal or incremental cost of service to ensure that customers of new rates and services contribute to margin.

Regulators most commonly grant marketing flexibility for rate and service offerings with certain characteristics. Generally speaking, flexibility is encouraged where new offerings are likely to benefit target customers while also benefitting other customers — for example, by increasing contributions to margins so that contributions by other customers can be reduced. Optional offerings have often been accorded expedited treatment by regulators because targeted customers are protected by their recourse to service under standard tariffs, as well as offerings by potential third-party providers that compete with the utility.

Several kinds of offerings may be deemed optional, such as:

1. A discount from rates in a standard tariff, offered to particular customers — for example, due to relatively high elasticity of their demands for utility services

2. An optional tariff that is available to all qualifying customers, such as a time-sensitive rate for electric vehicle charging

3. Special (negotiated) customer-specific contracts for utility services

4. A new premium quality service for customers prepared to pay for better quality

5. A discretionary service such as lighting on a backyard power pole

6. Special service packages (which may include standard services as components), such as a rate for a bundle of services that includes premium quality service and electric vehicle charging

Why MRPs Facilitate Marketing Flexibility

MRPs facilitate marketing flexibility for several reasons. Less frequent general rate cases reduce the chore of deciding how to allocate the revenue requirement between a complex and changing mix of market offerings. Multiyear rate plans also reduce concerns about cross-subsidies between service classes because infrequent rate cases and other plan provisions, such as service baskets, insulate core customers from potentially adverse consequences of marketing flexibility.[187] To the

[186] Decontrol of utility rate and service offerings is typically limited to markets that are robustly competitive.
[187] Cost trackers create a "back door" to cross-subsidization unless discounting of tracked costs is prohibited.

extent that the utility's earnings losses from special terms of services for certain customers can't be recovered from other customers, regulators are more confident that discounts are prudent.

In addition to facilitating marketing flexibility, MRPs create a special need for flexibility since rate cases are less frequently available as occasions for redesigning rates. Special proceedings to redesign rates in a revenue-neutral way can occur during an MRP. Alternatively, utilities may be permitted (or required) to gradually change rate designs during a rate plan in accordance with commission-approved goals. For example, the commission could approve a phase-in of time-sensitive usage charges.

MRPs can also strengthen utility incentives to improve marketing because the utilities are able to keep resultant margins longer. For example, under MRPs utilities have greater motivation to discourage load patterns that are especially costly. Under price caps, utilities have more incentive to encourage large-load customers to expand their operations.

Marketing Flexibility Precedents

Electric utilities have long been granted flexibility by regulators in rates and services they offer to some of the markets they serve. For example, rates utilities charge for use of their assets in various competitive markets are frequently not addressed by state regulators. Examples include sales in bulk power markets and rental of surplus office space. Light-handed regulation is sometimes accorded to special contracts for large-load customers with price-elastic demands or an interest in customized green power services.[188] However, special contracts for utility services require specific approval in many jurisdictions.

Multiyear rate plans have been extensively used to regulate utilities in industries where market-responsive rates and services are a priority. The example of Central Maine Power is discussed in Section 6 in this report. However, MRPs have not to date played a large role in fostering electric utility marketing flexibility. One reason is that many MRPs to date have applied to utility distribution companies, which traditionally had less need for special pricing for large-load customers.

A.4 Britain's Information Quality Incentive

Britain's Information Quality Incentive (IQI) rewards distributors for making conservative cost forecasts and then performing better.[189] The IQI is essentially a menu consisting of cost forecast-allowed revenue combinations. It currently applies to most operation and maintenance (O&M) expenses and capex. Each utility is asked to give a cost forecast and is eventually given an allowed revenue amount based on this forecast. The IQI's input on allowed revenue is in two parts: *ex-ante* allowed revenue and an IQI adjustment factor. By announcing its cost forecast, the utility implicitly chooses both its *ex-ante* allowed revenue and an IQI adjustment factor formula.

The *ex-ante* allowed revenue is a weighted average of the regulator's and the utility's cost forecasts. The regulator's forecast receives 75 percent weight while the utility's forecast receives

[188] Duke Energy (2015).
[189] Ofgem states that distributors with "less well justified capex forecasts, as compared with the views of Ofgem's consultants would be permitted to spend above the amounts that they had justified to Ofgem but [these distributors] would receive relatively lower returns for underspending. In contrast, those [distributors] that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency." See Ofgem (2009b), p. 38.

25 percent weight. This treatment alone greatly reduces the payoff to the distributor from a high cost forecast. The substantial weight assigned to the regulator's forecast reflects the large investment it makes in engineering and consulting services to develop an independent review of future cost.

The IQI adjustment factor is composed of an incentive rate and an additional income factor. The incentive rate specifies sharing, between utilities and customers, of variances between the utility's actual expenditures and the allowed revenue for these expenditures it was granted *ex ante*. The utility's share of these variances increases as the difference between the utility's cost forecast and regulator's own forecast decreases. The additional income factor, also referred to as an upfront reward or penalty, provides an immediate incentive for the utility to provide a cost forecast that is at or below Ofgem's own forecast.

Together these provisions make the menu "incentive compatible." The utility is rewarded when its cost forecast is low and its actual cost is similar. The IQI discourages a strategy of proposing a high forecast and subsequently incurring low costs.

Figure A-1 shows the IQI menu developed for the 2010-2015 plan:[190]

- The first row is a ratio of the utility's cost forecast to the regulator's cost forecast. A ratio of less than 100 means the utility has presented a lower cost forecast than the regulator, while a ratio above 100 means the utility's cost forecast is higher than the regulator's.

- The second row is the utility's share of what it over- or underspends relative to the *ex-ante* allowed revenue. The utility's share of these variances increases when its cost forecast is low. This feature provides greater incentives for the utility to cut costs and provide a forecast that is not inflated.

- The third row is the *ex-ante* revenue the utility can collect, expressed as a percentage of the regulator's cost forecast. This is much closer to Ofgem's forecast than to the utility's.

- The fourth row is the additional *ex post* income the utility can collect, expressed as a percentage of the regulator's cost forecast. This is a reward for a low cost forecast.

Values in the second section of Figure A-1, labeled IQI Adjustment Factor, illustrate possibilities for additional revenue (expressed as a percentage of Ofgem's cost forecast) which the utility can collect once it reports actual expenditures for the price control period. The amount of additional revenue depends on how the company's forecast compares to Ofgem's forecast and to the company's ultimate expenditures. The revenue adjustment is more favorable to the utility to the extent that its expenditures are low relative to its own forecast and Ofgem's forecast. The highest reward is offered for spending less than a utility forecast that was low relative to Ofgem's forecast.

[190] There have not been any major changes to the IQI methodology since this matrix was established.

Utility's cost forecast (% of Ofgem's cost forecast)	95	100	105	110	115	120	125	130	135	140
Utility's share of under/over spending (incentive rate)	0.53	0.5	0.48	0.45	0.43	0.4	0.38	0.35	0.33	0.3
Ex-ante allowed revenue (% of Ofgem's cost forecast)	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Ex-post additional income (% of Ofgem's cost forecast)	3.09	2.5	1.84	1.13	0.34	-0.5	-1.41	-2.38	-3.41	-4.5
Actual utility expenditure (% of Ofgem's cost forecast)	**IQI Adjustment Factor (% of Ofgem's cost forecast)**									
90	7.69	7.5	7.19	6.75	6.19	5.5	4.69	3.75	2.69	1.5
95	5.06	5	4.81	4.5	4.06	3.5	2.81	2	1.06	0
100	2.44	2.5	2.44	2.25	1.94	1.5	0.94	0.25	-0.56	-1.5
105	-0.19	0	0.06	0	-0.19	-0.5	-0.94	-1.5	-2.19	-3
110	-2.81	-2.5	-2.31	-2.25	-2.31	-2.5	-2.81	-3.25	-3.81	-4.5
115	-5.44	-5	-4.69	-4.5	-4.44	-4.5	-4.69	-5	-5.44	-6
120	-8.06	-7.5	-7.06	-6.75	-6.56	-6.5	-6.56	-6.75	-7.06	-7.5
125	-10.69	-10	-9.44	-9	-8.69	-8.5	-8.44	-8.5	-8.69	-9
130	-13.31	-12.5	-11.81	-11.25	-10.81	-10.5	-10.31	-10.25	-10.31	-10.5
135	-15.94	-15	-14.19	-13.5	-12.94	-12.5	-12.19	-12	-11.94	-12
140	-18.56	-17.5	-16.56	-15.75	-15.06	-14.5	-14.06	-13.75	-13.56	-13.5
145	-21.19	-20	-18.94	-18	-17.19	-16.5	-15.94	-15.5	-15.19	-15

Figure A-1. IQI Matrix for Ofgem's 5th Distribution Price Control Review.[191] IQI Matrix is an incentive compatible menu intended to encourage utilities to make low expenditure forecasts and then outperform them.

Suppose, by way of illustration, that a utility made a forecast that was just 5 percent above Ofgem's. Its *ex ante* allowed revenue would be only 1.25 percent above Ofgem's forecast, but it would be entitled to a fairly high 48 percent of surplus earnings and additional income equal to 1.84 percent of Ofgem's forecast. If its actual cost turned out to be the same as its forecast, it would garner an additional reward equal to 0.06 percent of Ofgem's forecast.

[191] Ofgem (2009c), p. 111. Presented here with some small changes to be more easily understood.

Appendix B. Details of the Technical Work

This appendix provides more technical details of two lines of research presented in this report. One is the numerical incentive power research. The other is the empirical research on power distributor productivity. We also discuss some statistical benchmarking concepts.

B.1 Incentive Power Research[192]

This section discusses incentive power research that PEG has conducted over the years on behalf of several utilities and regulatory commissions.[193] Implications of this research are summarized in Section 5 of this report.

Overview of Research

Our incentive power research considers how the performance of utilities differs under alternative regulatory systems that feature various performance-based regulation (PBR) features as well as systems that resemble traditional rate regulation. The research can be used to explore multiyear rate plan (MRP) design options such as earnings sharing mechanisms and alternative plan terms.

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions like those of a large energy distributor. In the first year of the decision problem, we assume for our example calculations that total annual cost is around $500 million for a company of average efficiency. Capital accounts for a little more than half of total cost. The annual depreciation rate is a constant 5 percent, the weighted average cost of capital is 7 percent, and the income tax rate is 30 percent.

Some assumptions have been made in the model to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time.[194] The utility's revenue will be the same year after year in the absence of a rate case.

The company has opportunities to reduce its cost through cost reduction initiatives. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one-year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years and five years. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we consider eight kinds of cost reduction projects — four for O&M expenses and four for capex. In our simulations, the company is permitted to pass up each kind of project in a given year (so that there is zero effort) but cannot choose *negative* levels of effort which constitute deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

The company can increase earnings by undertaking cost containment projects, but experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed to occur in

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[192] Further details of this research can be requested from the authors.
[193] Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the McCombs School of Business at the University of Texas.
[194] The comparatively low weighted-average cost of capital reflects these assumptions.

the first year of the initiative. We have assigned these unaccountable costs a value, in the reckonings of management as it crafts a business plan, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings, less the unaccountable costs of performance improvement just discussed, given the regulatory system, income tax rate and available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Reference Regulatory Systems[195]

We have developed five "reference" regulatory systems that constitute useful comparators for MRPs:

One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost every year. This has no real-world counterpart, since even traditional regulation requires at least a one-year rate case cycle and some incentive, once rates are set, to cut costs of base rate inputs. Another reference system is full externalization of the ratemaking process so that rates are no longer trued up periodically to the company's costs. Such an outcome would be obtained if the company were to embark on a permanent revenue cap regime.

The other three reference regimes approximate traditional regulation. In each, there is a predictable cycle of rate cases in which revenue is reset to the company's cost. We consider cycles of one, two and three years.

Multiyear Rate Plans

We considered various types of MRPs in our incentive power research. In most of these plans, there is no stretch factor shaving the revenue requirement mechanistically from year to year. The plans differ with respect to several kinds of provisions:

- *Plan term.* We consider terms of three, five, six and 10 years.

- *Impact of earnings sharing.* Plans considered also vary with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are zero, 25 percent, 50 percent and 75 percent. None of the mechanisms considered have dead bands or multiple sharing bands, as these complicate calculations.

- *How rates change with rate case.* Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most model runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle.[196] The qualification is that any upfront *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan.

- *Efficiency carryover mechanisms.* We also have considered the impact of some stylized efficiency carryover mechanisms. In one mechanism, the revenue requirement at the start of a new plan is based on a percentage (α%) of the cost in the last year of the previous plan and (1-

[195] The tables presented later in this appendix present results for these various scenarios.
[196] This is reasonable considering the lack of inflation and the stability of demand.

α)% on the revenue requirement in that year. This effectively permits the company to share (1-α)% any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90 percent to 50 percent.

In addition, we considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance between an exogenous benchmark value of cost in the last plan year and the actual cost incurred. The revenue requirement for the first year of the new MRP is thus a weighted average of the benchmark and actual cost. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

- *Avoided rate case option.* We also have considered a menu approach to incenting long-term efficiency gains. It gives the company the option at the end of the plan to start the new plan without a rate case. The revenue requirement for the next plan is in this eventuality established on the basis of a predetermined formula. The formula we consider is a stretch factor reduction in the revenue requirement established in the preceding rate case.[197] The company can thus avoid a rate case if it agrees to a starting revenue requirement for the new plan that regulators believe offers value to customers.

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function. An advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism.

Research Results

Tables B-1 to B-3 present a summary of results from the incentive power model. For each of several regulatory systems the tables show the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the tables, we report the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second plan and the long run. We discuss here only the long-run results.

Results are presented for 10 percent, 30 percent and 50 percent levels of initial operating inefficiency. We focus here on the 30 percent results since our benchmarking research over the years has suggested that this is a normal level of operating inefficiency. Table B-1 presents the 30 percent results. Tables B-2 and B-3 show that performance gains from more incentivized regulatory systems are generally larger for less efficient companies. Changes in productivity from the various PBR mechanisms are greatest in Table B-3 (companies starting with 50 percent inefficiency) and smallest in Table B-2 (companies starting with 10 percent inefficiency).

[197] In a world of input price and output growth, a more complex formula would be required.

Results for Reference Regulatory Systems

Table B-1 shows that no cost reduction initiatives are undertaken under cost plus regulation. This reflects the fact that there is no monetary reward for undertaking cost reduction initiatives, all of which involve unaccountable costs. At the other extreme, a complete externalization of future rates such as might occur if rate cases were never held again produces performance improvements relative to cost plus regulation that, over many years, accumulate to a net present value (NPV) of more than $2 billion. Average annual performance gains of 2.71 percent (or 271 basis points) are achievable in the long run.

As for the traditional regulatory systems, the system with a *three*-year cycle incents companies to achieve long-run savings with an NPV of about $900 million — a major improvement over cost plus regulation but less than half of the savings that are potentially available from efficiency initiatives. Average annual performance gains rise from zero to 0.90 percent. The fact that some cost savings occur under traditional regulation is not surprising inasmuch as the assumed three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects with one-year payback periods. A two-year rate case cycle produces only 0.66 percent annual performance gains.

Table B- 1 Results From the Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain* First two rate cycles	Average Annual Performance Gain* Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table B-2 Results From the Incentive Power Model: 10% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table B-3. Results From the Incentive Power Model: 50% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Plan Term

Consider now the effect of extending the plan term beyond the conventional three-year rate case cycle. Extending the term from three years to five years increases annual performance gains by about 51 basis points in the long run. Evidently, stronger performance incentives elicit better performance. Extending the term from three years to 10 years increases average annual performance gains by 133 basis points.

The benefits of a longer plan term are greater when rate cases would be more frequent under traditional regulation. For example, if rate cases would otherwise be held every two years, a five-year MRP with no earnings sharing produces 75 basis points of additional annual performance gains in the long run.

Impact of Earnings Sharing

The third panel of Table B-1 shows that the addition of earnings sharing mechanisms (ESMs) reduces cost savings compared to a plan of the same duration with no sharing mechanism. For example, a five-year plan in which the company keeps 75 percent of earnings variances produces only 27 basis points of additional performance gains annually in the long run compared to a three-year rate case cycle.

However, plans with an earnings sharing mechanism can deliver more cost savings than a pattern of frequent rate cases. For example, a five-year plan with 75/25 sharing produces 51 more basis points of annual performance gains than traditional regulation with a two-year cycle.

Impact of Efficiency Carryover Mechanism

Let’s consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. The fourth panel of Table B-1 shows that, in the context of a five-year rate plan, assigning the benchmark a weight of 25 percent produces 35 basis points of additional performance gains. Of greater interest perhaps is that it boosts the performance gains from a three-year plan by a substantial 76 basis points. Thus, this efficiency carryover mechanism can give a three-year plan considerable incentive power.

Let’s turn now to the alternative efficiency carryover mechanism approach in which cost in the historical reference year is compared to a *fully external* benchmark such as that produced by an econometric model developed using industry data. Remarkably, the fifth panel of Table B-1 shows that assigning the benchmark a weight of only 25 percent more than doubles the cost savings produced by three-year plans. This suggests that a benchmark-based efficiency carryover mechanism has the potential to strengthen performance incentives rather dramatically. With a *five*-year rate case cycle, the effect of the same 25 percent externalization is still substantial, but more modest than in a three-year cycle. This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term.

Impact of Rate Case Avoidance

Let’s turn now to the impact of rate case avoidance. The sixth panel of Table B-1 shows that, in three-year plans with stretch factors of 1 percent, 1.5 percent and 2 percent, this approach produces the same dramatic cost efficiency savings that would result from full rate externalization. Evidently, the company judges that with a high level of cost containment effort it can get its costs permanently below the cost growth target and acts accordingly.

Conclusions

Our incentive power research for this report yields important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the frequency of rate cases can have a material impact on utility cost performance. Under COSR, performance will be considerably better when rate cases typically occur every three years than when they typically occur every two years. Thus, the favorability of business conditions affects operating performance.

Our research also shows that an MRP with a five-year rate case cycle can simulate the stronger incentives, especially when rate cases are more frequent than every three years. In addition, an MRP should have advantages when the alternative is pervasive cost trackers. Incentives are weakened under an ESM. We also show that adding innovative plan provisions on the frontier of PBR, such as efficiency carryover mechanisms and menus, can materially strengthen performance incentives. Many of the real-world plans reviewed in this report did not have these incentive power "turbochargers."

B.2 Utility Productivity Research

We presented results of our utility productivity research in Section 6 of this report. This section of Appendix B discusses productivity and revenue cap indexes, sources of productivity growth, and productivity trends of U.S. power distributors. We also provide mathematical details of the calculations.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity index (Outputs) to an input quantity index (Inputs):

$$Productivity = \frac{Outputs}{Inputs} \qquad [B1]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. The growth trend of a productivity trend index can then be shown mathematically to be the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [B2]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is typically due to fluctuations in output, the uneven timing of certain expenditures, or both. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity index measures productivity in the use of multiple inputs.

The output (quantity) index of a firm or industry summarizes trends in the scale of operation. Growth in each output dimension that is itemized is measured by a subindex. One possible objective of output research is to measure the impact of output growth on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers.[198] A productivity index calculated using a cost-based output index may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than output. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when output growth slows.

A third important source of productivity growth is change in inefficiency. Inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when inefficiency diminishes (increases). The lower the company's current efficiency level, the greater the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines that are undergrounded will tend to slow multifactor productivity growth (because of the higher capital requirements) but accelerate O&M productivity growth (since there is less line maintenance).

Finally, consider that in the short to medium run a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

Revenue Cap Indexes

Index research provides the basis for revenue cap indexes. The following basic result of cost research is a useful starting point:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Outputs} \qquad \text{[B3]}$$

The cost trend is the difference between the trends in input price and productivity indexes plus the trend in operating scale as measured by a cost-based output index. This result provides the rationale for a revenue cap escalator of the following general form:

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Outputs} \qquad \text{[B4a]}$$

where

$$X = \overline{MFP} + \textit{Stretch}. \qquad \text{[B4b]}$$

[198] The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Here X, the "X factor," is calibrated to reflect a base MFP growth target ($\overline{MFP}$). A "stretch factor" is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements expected during the MRP. Since the X factor often includes *Stretch,* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

For electric power distributors, the number of customers served is a useful scale variable for a revenue cap index. Relation [B3] can then be restated as:

$$\begin{aligned} &\textit{trend Cost} \\ &\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &\quad = \textit{trend Input Prices} - \textit{trend } MFP^{N} + \textit{trend Customers} \end{aligned} \qquad \text{[B5a]}$$

where MFP^{N} is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [B5a] we obtain:

$$\begin{aligned} &\textit{trend Cost} - \textit{trend Customers} \\ &= \textit{trend } (\textit{Cost/Customer}) = \textit{trend Input Prices} - \textit{trend } MFP^{N}. \end{aligned} \qquad \text{[B5b]}$$

This provides the basis for the following revenue per customer index formula:[199]

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad \text{[B6]}$$

where

$$X = \overline{MFP^{N}} + \textit{Stretch}.$$

Productivity Trends of U.S. Power Distributors

<u>Data</u>

The primary source of our cost and quantity data is FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[200] More recently, the data have been available electronically in raw form from FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG Research. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 in 1964 (the benchmark year for our study, described further below)

[199] This general formula for the design of revenue cap indexes is currently used in the PBR plans of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada, respectively.

[200] This publication series had several titles over the years. A recent title is Financial Statistics of Major US Investor-Owned Electric Utilities.

and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the study the data also were required to be of good quality and plausible. One important quality criterion was that there were no major shifts in cost between the distribution and transmission plant. Data from 86 utilities met our standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table B-4 lists the companies from which data were drawn. Most broad regions of the United States are well-represented.[201]

Scope of Research

The total cost of power distributor services considered in the study was the sum of applicable O&M expenses and capital costs. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.[202] We also excluded expenses for purchased power and customer service and information. The featured results employed a geometric decay approach to capital cost measurement that is explained further below. Capital cost is the sum of depreciation expenses, a return on the value of net plant, taxes and capital gains.

We calculated indexes of growth in the O&M, capital, and multifactor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

[201] Unfortunately, the requisite customer data are not available for most Texas distributors.
[202] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1 for easy removal. We exclude customer service and information expenses because on FERC Form 1 these include DSM expenses.

Table B-4. Companies Included in Our Power Distributor Productivity Research

Alabama Power	MDU Resources Group
ALLETE (Minnesota Power)	Metropolitan Edison
Appalachian Power	MidAmerican Energy
Arizona Public Service	Mississippi Power
Atlantic City Electric	Monongahela Power
Avista	Narragansett Electric
Baltimore Gas and Electric	Nevada Power
Central Hudson Gas & Electric	New York State Electric & Gas
Central Maine Power	Niagara Mohawk Power
Cleco Power	Northern States Power - MN
Cleveland Electric Illuminating	Northwestern Public Service
Connecticut Light and Power	Nstar Electric
Consolidated Edison	Ohio Edison
Dayton Power and Light	Ohio Power
Delmarva Power & Light	Oklahoma Gas and Electric
Duke Energy Carolinas	Orange and Rockland Utilities
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	Pacific Gas and Electric
Duke Energy Kentucky	PacifiCorp
Duke Energy Ohio	PECO Energy
Duke Energy Progress	Pennsylvania Electric
Duquesne Light	Pennsylvania Power
El Paso Electric	Portland General Electric
Empire District Electric	Public Service Company of Colorado
Entergy Louisiana	Public Service Company of Oklahoma
Entergy Mississippi	Public Service Electric and Gas
Entergy New Orleans	Rochester Gas and Electric
Fitchburg Gas and Electric Light	San Diego Gas & Electric
Florida Power & Light	South Carolina Electric & Gas
Georgia Power	Southern California Edison
Green Mountain Power	Southern Indiana Gas and Electric
Gulf Power	Superior Water, Light and Power
Idaho Power	Tampa Electric
Indiana Michigan Power	Toledo Edison
Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	United Illuminating
Kansas City Power & Light	Virginia Electric and Power
Kansas Gas and Electric	West Penn Power
Kentucky Power	Western Massachusetts Electric
Kentucky Utilities	Wheeling Power
Kingsport Power	Wisconsin Electric Power
Louisville Gas and Electric	Wisconsin Power and Light
Massachusetts Electric	Wisconsin Public Service

Number of Sampled Companies: 86

The major tasks in a power distributor's operation are the local delivery of power and the reduction of its voltage. Most power is delivered to end users at the voltage at which it is consumed. U.S. distributors also typically provide an array of customer services such as metering and billing.

Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. We used as a proxy for output growth the growth in the total number of retail customers served.

In calculating input quantity trends, we broke down the applicable cost into those for distribution plant, general plant, labor, and material and service (M&S) inputs. The cost of labor was defined for this purpose as O&M salaries and wages and pensions and other benefits. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of the multifactor input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

Sample Period

The full sample period for which productivity results were calculated was 1980-2014.[203]

Index Results

Table B-5 summarizes our productivity research for the full sample. Over the full 1980-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was about 0.45 percent. Customer growth averaged 1.16 percent annually, whereas input growth averaged 0.70 percent. O&M productivity growth averaged 0.53 percent while capital productivity growth averaged 0.43 percent. O&M productivity growth was much more volatile than capital productivity growth.

[203] In other words, 1980 was the earliest year for growth rate calculations.

Table B-5. U.S. Power Distribution Productivity Trends

	Output	Inputs	PFP O&M	PFP Capital	MFP
1980	1.77%	2.26%	-4.19%	1.24%	-0.49%
1981	1.66%	1.49%	-2.42%	1.25%	0.17%
1982	1.63%	0.76%	-1.20%	1.53%	0.87%
1983	0.96%	0.45%	-0.38%	0.98%	0.51%
1984	1.60%	0.33%	-0.22%	1.79%	1.27%
1985	1.71%	0.76%	-0.21%	1.37%	0.95%
1986	1.70%	0.79%	0.88%	0.97%	0.91%
1987	1.77%	1.33%	-0.12%	0.68%	0.44%
1988	1.47%	0.90%	1.55%	0.24%	0.57%
1989	1.49%	1.23%	0.00%	0.23%	0.26%
1990	1.42%	1.25%	0.64%	-0.05%	0.18%
1991	1.17%	1.20%	0.58%	-0.32%	-0.03%
1992	1.12%	0.64%	1.61%	0.10%	0.48%
1993	1.41%	0.96%	1.19%	0.12%	0.45%
1994	1.39%	0.45%	2.44%	0.29%	0.94%
1995	1.40%	0.46%	3.58%	-0.04%	0.94%
1996	1.16%	1.05%	0.67%	-0.13%	0.11%
1997	1.37%	-0.16%	4.68%	0.39%	1.53%
1998	1.54%	0.87%	0.73%	0.71%	0.67%
1999	0.81%	-0.27%	2.24%	0.52%	1.08%
2000	1.37%	0.48%	0.86%	0.73%	0.89%
2001	1.59%	0.39%	2.73%	0.61%	1.20%
2002	1.17%	0.38%	2.73%	0.33%	0.79%
2003	1.14%	1.17%	-1.50%	0.43%	-0.03%
2004	1.06%	0.66%	0.76%	0.22%	0.41%
2005	1.07%	1.14%	-0.25%	0.09%	-0.07%
2006	0.51%	1.03%	-1.07%	-0.21%	-0.52%
2007	1.02%	1.14%	0.00%	-0.02%	-0.12%
2008	0.54%	1.53%	-2.06%	-0.09%	-0.99%
2009	0.26%	-0.75%	2.73%	-0.46%	1.01%
2010	0.45%	0.72%	-0.47%	0.05%	-0.27%
2011	0.28%	-0.22%	0.05%	0.50%	0.50%
2012	0.39%	-0.91%	2.90%	0.58%	1.29%
2013	0.44%	0.41%	0.40%	-0.05%	0.03%
2014	0.65%	0.68%	-1.41%	0.56%	-0.03%
Average Annual Growth Rates					
1980-2014	**1.16%**	**0.70%**	**0.53%**	**0.43%**	**0.45%**
1996-2014	**0.88%**	**0.49%**	**0.77%**	**0.25%**	**0.39%**
2008-2014	**0.43%**	**0.21%**	**0.30%**	**0.15%**	**0.22%**

Over the more recent 1996-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was similar, at 0.39 percent. Customer growth slowed modestly to average 0.88 percent annually, while input growth averaged 0.49 percent annually. O&M productivity growth accelerated to average 0.77 percent, while capital productivity growth slowed to average 0.25 percent.

Since 2007 the MFP growth of power distributors has slowed modestly, averaging 0.22 percent annually. This is mainly due to a slowdown in O&M productivity growth, which averaged 0.30 percent annually. Capital productivity growth slowed slightly to average 0.15 percent.

Table B-6 provides the annual growth rates in the MFP indexes for the individual utilities in our sample. We report results for the full sample period (1980-2014) and for the 1996-2014 and 2008-2014 sample periods.

Additional Details on Productivity Research

Input Quantity Indexes. The quantity subindex for labor is the ratio of salary and wage expenses to a regionalized salary and wage labor price index.[204] The quantity subindex for M&S inputs is the ratio of the expenses to the GDPPI. Details of the capital quantity index are provided below.

The summary quantity indexes for O&M, capital, and all inputs were of chain-weighted Törnqvist form.[205] This means that their annual growth rate was determined by the following general formula:

$$ln\left(Inputs_t / Inputs_{t-1}\right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1}\right) \cdot ln\left(X_{j,t} / X_{j,t-1}\right) \qquad [B7]$$

where in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost

[204] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.
[205] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Table B-6. Power Distributor MFP Trends of Individual U.S. Electric Utilities

	Average Annual MFP Growth Rate		
Distributor	**1980-2014**	**1996-2014**	**2008-2014**
Alabama Power	-0.52%	-0.61%	-0.50%
ALLETE (Minnesota Power)	0.86%	1.32%	0.54%
Appalachian Power	0.12%	0.38%	-0.29%
Arizona Public Service	0.39%	0.88%	0.98%
Atlantic City Electric	0.37%	0.10%	-1.37%
Avista	0.41%	0.09%	-0.71%
Baltimore Gas and Electric	0.35%	-0.06%	-1.08%
Central Hudson Gas & Electric	0.81%	-0.04%	-0.45%
Central Maine Power	0.66%	0.79%	0.28%
Cleco Power	-0.14%	-0.35%	-0.42%
Cleveland Electric Illuminating	0.40%	0.49%	0.05%
Connecticut Light and Power	0.41%	-0.10%	0.03%
Consolidated Edison	0.06%	-0.45%	-0.44%
Dayton Power and Light	0.84%	0.35%	-0.93%
Delmarva Power & Light	0.60%	0.71%	-1.08%
Duke Energy Carolinas	-0.04%	1.09%	0.75%
Duke Energy Florida	0.64%	0.38%	1.00%
Duke Energy Indiana	0.58%	0.08%	-0.09%
Duke Energy Kentucky	0.35%	0.54%	-1.24%
Duke Energy Ohio	0.58%	0.81%	-0.87%
Duke Energy Progress	0.56%	0.65%	1.35%
Duquesne Light	0.64%	0.73%	0.04%
El Paso Electric	0.88%	0.45%	-0.17%
Empire District Electric	-0.09%	-0.26%	-0.65%
Entergy Louisiana	0.63%	0.71%	1.86%
Entergy Mississippi	-0.01%	-0.17%	0.40%
Entergy New Orleans	0.43%	-0.54%	4.37%
Fitchburg Gas and Electric Light	0.34%	0.22%	0.98%
Florida Power & Light	0.84%	0.66%	1.06%
Georgia Power	0.40%	1.11%	1.09%
Green Mountain Power	0.82%	0.52%	1.05%
Gulf Power	0.21%	0.28%	-0.39%
Idaho Power	1.29%	1.48%	1.23%
Indiana Michigan Power	0.30%	-0.02%	-0.46%
Indianapolis Power & Light	0.81%	1.17%	0.86%
Jersey Central Power & Light	0.68%	0.63%	0.84%
Kansas City Power & Light	1.01%	0.76%	0.37%
Kansas Gas and Electric	0.70%	0.57%	0.18%
Kentucky Power	-0.71%	-0.56%	-1.42%
Kentucky Utilities	0.18%	0.01%	-2.38%
Kingsport Power	0.46%	0.23%	-1.33%
Louisville Gas and Electric	0.33%	0.20%	-2.39%
Massachusetts Electric	0.96%	1.10%	0.72%
MDU Resources Group	0.61%	0.76%	1.01%
Metropolitan Edison	1.25%	1.42%	1.06%

Table B-6 (continued) Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	1980-2014	1996-2014	2008-2014
MidAmerican Energy	0.04%	1.22%	2.37%
Mississippi Power	-1.18%	-1.42%	0.65%
Monongahela Power	0.10%	0.57%	0.54%
Narragansett Electric	0.80%	0.57%	-0.03%
Nevada Power	0.99%	1.12%	1.67%
New York State Electric & Gas	1.02%	1.57%	1.51%
Niagara Mohawk Power	0.54%	0.81%	0.68%
Northern States Power - MN	0.73%	0.26%	1.06%
Northwestern Public Service	0.30%	0.68%	1.01%
Nstar Electric	0.40%	0.59%	1.14%
Ohio Edison	0.97%	1.34%	1.02%
Ohio Power	0.28%	0.45%	-0.20%
Oklahoma Gas and Electric	0.14%	-0.07%	-0.49%
Orange and Rockland Utilities	0.82%	0.32%	0.07%
Otter Tail Power	0.00%	0.04%	0.37%
Pacific Gas and Electric	0.24%	-0.04%	0.10%
PacifiCorp	0.08%	1.18%	2.26%
PECO Energy	0.91%	0.16%	-0.21%
Pennsylvania Electric	0.84%	0.94%	1.15%
Pennsylvania Power	0.60%	0.75%	0.51%
Portland General Electric	0.57%	-0.72%	0.10%
Public Service Company of Colorado	0.72%	0.01%	0.90%
Public Service Company of Oklahoma	0.00%	-0.43%	0.07%
Public Service Electric and Gas	0.80%	0.76%	0.49%
Rochester Gas and Electric	1.05%	0.64%	0.97%
San Diego Gas & Electric	-0.31%	-0.41%	0.21%
South Carolina Electric & Gas	0.16%	0.21%	0.02%
Southern California Edison	-0.08%	-0.45%	-1.47%
Southern Indiana Gas and Electric	0.29%	-0.03%	-1.19%
Superior Water, Light and Power	0.57%	0.31%	-0.40%
Tampa Electric	0.97%	0.80%	0.42%
Toledo Edison	1.07%	1.13%	0.94%
Union Electric	0.38%	0.25%	0.45%
United Illuminating	-0.72%	-1.51%	-5.50%
Virginia Electric and Power	0.65%	0.88%	0.64%
West Penn Power	0.83%	1.38%	1.73%
Western Massachusetts Electric	0.75%	1.01%	0.42%
Wheeling Power	0.11%	-0.19%	-1.06%
Wisconsin Electric Power	0.41%	0.11%	0.74%
Wisconsin Power and Light	-0.04%	-0.29%	-0.38%
Wisconsin Public Service	0.82%	0.57%	2.31%
Full Sample Averages	**0.45%**	**0.39%**	**0.22%**

The growth rate of each summary index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of each utility in the current and prior years served as weights.

*Productivity Growth Rates and Trends***.** The annual growth rate in each company's productivity index is given by the formula:

$$ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right)$$
$$= ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right) \quad [B8]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Capital Cost Measurement. A service price approach is used to measure capital costs. This approach has a solid basis in economic theory and is widely used in scholarly empirical work. In the application of the general method used in this study, the cost of a given class of utility plant j in a given year t ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,\ t-1}$):

$$CK_{j,t} = WKS_{j,t} \bullet XK_{j,\ t-1} \quad [B9a]$$

It can then be shown mathematically that:

$$growth\ CK_{j,t} = growth\ WKS_{j,t} + growth\ XK_{j,\ t-1} \quad [B9b]$$

In constructing both indexes we used the geometric decay approach. We took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net distribution plant by dividing this book value by a triangularized weighted average of 37 values of an index of utility construction cost for a period ending in the benchmark year.[206] The construction cost index (WKA_t) was the applicable regional Handy-Whitman index of the cost of the relevant asset category.[207]

The following formula was used to compute subsequent values of each capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \quad [B10]$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The economic depreciation rate was set at 4.34 percent for distribution plant. It is based on a weighted average of economic depreciation rates for different types of distribution assets. The depreciation rate also reflects declining balance parameters that were 0.91 for structures and 1.65 for equipment.

---

[206] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This make sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

[207] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Following is the full formula for the capital service price indexes for each asset category:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [B11]$$

The first term in the expression corresponds to the cost of taxes and utility franchise fees ($CK_{j,t}^{Taxes}$). The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

The calculation of [B11] requires an estimate of the rate of return on capital (r_t). We employed a weighted average of rates of return for debt and equity.[208] Prior to 1995, we relied on a 50/50 average of the average yield on AA utility bonds and ROE using data from Moody's.[209] For subsequent years, we relied on a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data and the average allowed rate of ROE approved in electric utility rate cases for each year as reported by the Edison Electric Institute.[210]

B.3 Statistical Benchmarking

Quantitative performance benchmarking commonly involves one or more gauges of activity. These are sometimes called *key performance indicators* (KPIs) or *metrics.* The values of these indicators for a utility are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark one might, for instance, measure its cost performance by taking the ratio of the two values:

$$Cost\ Performance = Cost^{Actual} / Cost^{Benchmark}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in the calculation of benchmarks and are sometimes used in performance appraisals. An approach to benchmarking that features statistical methods is called *statistical benchmarking.*

Econometric Benchmarking

Cost benchmarks should reflect the cost pressures a utility faces. The impact of external business conditions on the costs of utilities can be estimated using statistics. Consider, by way of example, the following simple model of power distributor cost. In a given year *t*, the cost of power distributor *h* ($C_{h,t}$) is a function of the number of customers it serves ($N_{h,t}$) and the market wage rate ($W_{h,t}$):

$$C_{h,t} = a_0 + a_1 N_{h,t} + a_2 W_{h,t} \qquad [B12]$$

The parameters a_1 and a_2 determine the impact of the business conditions on cost.

[208] This calculation was made solely for the purpose of measuring productivity trends and does not prescribe appropriate rate of return levels for utilities.
[209] Moody's Public Utility Manual (1995).
[210] Edison Electric Institute.

A branch of statistics called *econometrics* has developed procedures for estimating the parameters of economic functions using historical data.[211] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. Abundant, high quality data are available for this purpose from the federal government. The sample used in model estimation is typically a "panel" data set that pools time series data for several companies.

Tests can be constructed for the hypothesis that the parameter for a candidate cost driver equals zero. A variable is deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

A cost function fitted with econometric parameter estimates may be called an *econometric cost model.* We can use such a model to predict a company's cost given local values for cost driver variables. These predictions are econometric benchmarks. Cost performance can be measured by comparing a company's cost in year *t* to the cost projected for that year and company by the econometric model. There is no need to choose a peer group because the methodology uses the exact business conditions faced by the benchmarked company.

Suppose, for example, that we wish to benchmark the cost of a hypothetical utility called Eastern Edison. We might then predict the cost of Eastern Edison in period *t* using the following model constructed from [B12]:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Eastern,t} + \hat{a}_2 \cdot W_{Eastern,t} \; . \qquad [B13]$$

Here $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $N_{Eastern,t}$ is the number of customers it served, and $W_{Eastern,t}$ measures the wage rate in its region. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = {C_{Eastern,t}} \big/ {\hat{C}_{Eastern,t}} \; .$$

Table B-7 provides details of the econometric model of total power distributor cost that is used to set stretch factors in the IRM4 multiyear rate plan in Ontario. There is one input price variable (a capital price index), three scale variables (the number of customers, the retail delivery volume, and peak demand), two additional business conditions (average line length and a system age variable), and a trend variable. Note that the number of customers is the scale variable with the highest parameter estimate and t statistic. This model has a translogarithmic functional form so that, in addition to the "first order terms" representing the basic business condition variables, there are interaction and quadratic terms for the price and output variables. Model parameters were estimated using Ontario data

[211] The estimation of model parameters is sometimes called regression.

Table B-7. Econometric Cost Model for Ontario[212]

VARIABLE KEY

Input Price: WK = Capital Price Index
Outputs: N = Number of Customers
C = System Capacity Peak Demand
D = Retail Deliveries
Other Business Conditions: L = Average Line Length (km)
NG = % of 2012 Customers added in the last 10 years
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6271	85.5530
N*	0.4444	8.0730
C*	0.1612	3.2140
D*	0.1047	3.4010
WKxWK*	0.1253	4.5320
NxN	-0.3776	-1.6160
CxC	0.1904	0.9340
DxD*	0.1646	2.1660
WKxN*	0.0536	3.4540
WKxC	0.0100	0.7200
WKxD	-0.0001	-0.0100
NxC	0.1415	0.7040
NxD	0.0674	0.6790
CxD*	-0.1990	-2.3070
L*	0.2853	13.9090
NG*	0.0165	2.4110
Trend*	0.0171	12.5700
Constant*	12.815	683.362
System Rbar-Squared	0.983	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

[212] Kaufmann, Hovde, Kalfayan, and Rebane (2013), p. 58.

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20-Apr-2023 | 16:26 EDT

American Electric Power Ratings Affirmed; Kentucky Power Downgraded To 'BBB' On Weaker Financials; Outlook Stable

- On April 17, 2023, American Electric Power Co. Inc. (AEP) and Liberty Utilities Co. mutually agreed to terminate the sale of Kentucky Power Co. (KPCo).
- As such, we affirmed our ratings on AEP, including its 'A-' long-term issuer credit rating (ICR). The outlook remains stable.
- Simultaneously, we lowered the ICR and issue-level ratings on KPCo by one notch to 'BBB' from 'BBB+'. At the same time, we removed KPCo ratings from CreditWatch, where we placed them with negative implications on Oct. 28, 2021. The outlook is stable.
- Our stable outlook on AEP reflects our expectations that the company's financial measures will improve but will consistently reflect very minimal financial cushion from its downgrade threshold. We expect the company will continue to prudently manage its regulatory risk such that it consistently maintains funds from operations (FFO) to debt that is at or slightly above 16% through 2025.

NEW YORK (S&P Global Ratings) April 20, 2023--S&P Global Ratings today took the rating actions listed above.

We expect that AEP's financial measures will significantly improve.

AEP's 2022 FFO debt was 14.9%, considerably below our 16% downgrade threshold. We expect financial measures will significantly improve in 2023, primarily reflecting the company's sale of its unregulated contracted renewable assets, equity units conversion of about $850 million, and rate case orders in Oklahoma and Virginia. However, despite our anticipation for additional material equity issuances in 2024 and 2025, we expect the company's financial measures will reflect only very minimal financial cushion above our downgrade threshold because of robust capital spending. Over the next three years, we expect annual capital spending to average about $8.5 billion. This is a significant increase from the company's historical capital spending levels. In 2021 and 2022, AEP's capital spending was about $5.7 billion and $6.7 billion, respectively. As such, the company must continue to consistently manage its regulatory risk at all of its regulatory jurisdictions. Any unexpected outcomes beyond our base case could weaken financial measures below our downgrade threshold, potentially leading to a weakening of credit quality.

We continue to assess AEP's business risk profile as excellent.

We assess AEP's business risk profile as being in the middle of the range for the excellent category, relative to peers. The company is mostly a large and geographically diversified regulated utility that serves about 5.6 million customers across 11 states. The company's ongoing reduction of its coal-fired generation aligns with the industry's transition toward a clean energy future. We expect a modest improvement in the business risk profile with the sale of unregulated contracted renewables portfolio occurring in the second half of 2023.

The downgrade of KPCo to 'BBB' from 'BBB+' reflects the company's stand-alone weakening financial measures.

In 2021 and 2022, FFO to debt was 11.6% and 11.4%, respectively, significantly below our downgrade threshold of 15%. We reflect this weakening in financial measures by applying a negative comparable ratings analysis modifier. Going forward, we expect a modest improvement to stand-alone financial measures, reflecting rate case increases and a potential securitization, pending legislative and regulatory approvals.

We revised our assessment of Indiana Michigan Power Co's (IMP) financial risk profile downward to significant from intermediate.

This reflects our expectation of a modest weakening of financial measures primarily reflecting robust capital spending. We now expect IMP's stand-alone FFO to debt to be about 18%-23% through 2025. We also expect IMP's capital spending to gradually rise to about $1 billion by 2025. We expect IMP's discretionary cash flow to remain negative and anticipate it will continue to depend on having consistent access to the capital markets.

American Electric Power Co. Inc.

The stable rating outlook on AEP reflects our expectations that the company's financial measures will improve but will consistently reflect very minimal financial cushion from its downgrade threshold. We expect the company will continue to prudently manage its regulatory risk such that it consistently maintains FFO to debt that is at or slightly above 16% through 2025.

We could lower our ratings on AEP within the next 24 months if:

- Its financial performance does not improve as expected such that FFO to debt remains below 16%; or
- Its business risk increases because of ineffective management of regulatory risk or an increase in its riskier nonregulated investments.

While less likely, we could upgrade AEP if its financial performance materially improves such that FFO to debt is consistently greater than 20% without any increase to business risk.

Kentucky Power Co.

The stable outlook on KPCo reflects timely recovery of approved capital expenditure and fuel costs, supporting the company's cash flow stability. Our baseline forecast for 2023-2025 assumes KPCo's stand-alone FFO to debt to be in the range of 11%-15%.

We could lower our ratings on KPCo in the next 24 months if:

- Parent AEP is downgraded; or
- KPCo's stand-alone financial performance weakens such that FFO to debt weakens to below 11%.

We could upgrade KPCo if its stand-alone financial performance improves such that FFO to debt is greater than 15%, without an increase to business risk.

American Electric Power Co. Inc.

ESG credit indicators: E-3, S-3, G-2

Indiana Michigan Power Co.

ESG credit indicators: E-4, S-3, G-2

Kentucky Power Co.

ESG credit indicators: E-4, S-3, G-2

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Edison Electric Institute

Alternative Regulation for Emerging Utility Challenges: 2015 Update

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Contents

I. Introduction

Investor-owned electric utilities in the United States are buffeted today by varied and rapid changes in the business conditions they face. For vertically integrated electric utilities ("VIEUs") and utility distribution companies ("UDCs") alike, the traditional cost of service approach to rate regulation is often not ideal for helping utilities cope with these changes. Alternative approaches to regulation ("Altreg") can often help utilities secure better outcomes for their customers and shareholders.

The changing business climate stems primarily from three root causes. One is pressure, from policymakers and many customers, for the power industry to lighten its environmental footprint. In addition to evolving renewable portfolio standards at the state level, utilities must comply with an array of federal initiatives such as the Environmental Protection Agency's Clean Power Plan. Demand-side management ("DSM") programs and tightening building codes and appliance standards encourage energy efficiency. Some customers seek power from greener sources than the increasingly clean portfolios of utilities. Self generation from rooftop solar is one means to this end, and its cost is falling. Customer-sited distributed generation ("DG") must be accommodated, and utilities must purchase power surpluses that these facilities generate at regulated rates.

A second force for change is technological progress in metering and distribution. Advanced metering infrastructure and other smart grid technologies can improve reliability and facilitate integration of intermittent renewables. Time-sensitive pricing can encourage customers to use the grid in less costly ways. New value-added optional products and services can be offered which benefit customers.

A third force for change is increased concern about the reliability and resiliency of grid service. Some facilities are approaching advanced age, and some need more protection from severe weather. Many customers seek better quality service.

These forces are having important practical effects on utilities. Growth in the demand for their traditional services has slowed, and utilities face competition from distributed energy resources ("DERs"). Nevertheless, some utilities need capital expenditures ("capex") for cleaner generating capacity, smart grid facilities, increased resiliency, and replacement of aging assets. Many new facilities don't automatically trigger revenue growth. Increased marketing flexibility is needed to meet competitive challenges and complex, changing customer needs.

Under traditional regulation, the base rates that compensate utilities for costs of non-energy inputs are reset only in general rate cases with historical test years. These lengthy proceedings require a detailed review of all costs and their allocation amongst the utility's retail services. Revenue from secondary sources (e.g., off-system sales) is imputed against the revenue requirement.

Most base rate revenue is drawn from volumetric and other usage charges. Since the cost of base rate inputs is driven more by capacity than system use in the short run, a utility's finances are sensitive between rate cases to the gap between growth in system use and capacity. A convenient proxy for this gap is the growth in use per customer (aka "average use"). The need for rate cases increases when average use declines.

Traditional regulation is ill-suited for addressing many of today's challenges. Growth in average use was once positive, and the resulting incremental revenues helped utilities finance rising cost without rate cases. Today, growth in the average use of residential and commercial customers is typically static and often negative. Utilities needing normal or high capital expenditures are then compelled to file rate cases more frequently. These involve high regulatory cost and are nonetheless frequently uncompensatory when they involve historical test years. Frequent rate cases also reduce utility opportunities to increase earnings from improved cost containment and marketing. Traditional regulation also does not allow for many value-added or optional rates and services. Improved utility performance is thus discouraged at a time when it is increasingly needed to respond to competitive pressures.

Increased financial attrition has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, can involve sweeping regulatory change. Others, like revenue decoupling and cost trackers, target specific challenges.

This survey, now updated to include precedents through mid-2015, explains Altreg options and details precedents in the regulation of retail electric utility rates. A summary of states that currently use these approaches is featured in Table 1. Information is also provided on precedents for gas and water distributors and for energy utilities in Australia, Canada, and Britain. This year's survey also discusses marketing flexibility, a new Altreg area of growing interest to EEI members.

Figure 1

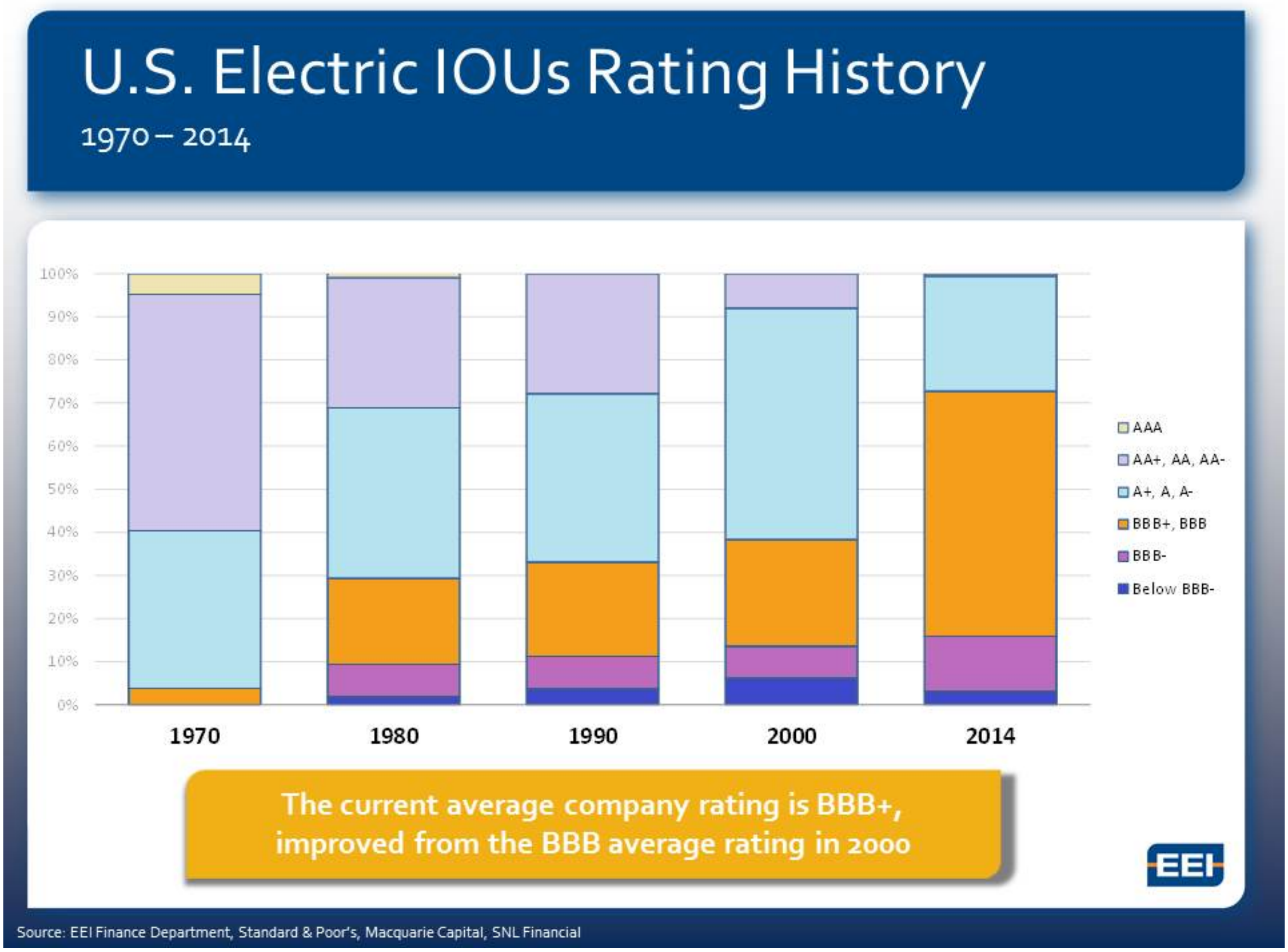
U.S. Electric IOUs Rating History
1970 – 2014
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1970
1980
1990
2000
2014
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
Below BBB-
The current average company rating is BBB+, improved from the BBB average rating in 2000
EEI
Source: EEI Finance Department, Standard & Poor's, Macquarie Capital, SNL Financial

Table 1

Alternative Regulation Tools: An Overview of Current Precedents

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Alabama	Electric & Gas					Electric & Gas	Yes
Alaska							
Arizona	Electric, Gas, & Water	Gas only	Electric & Gas		Electric only		
Arkansas	Electric & Gas	Gas only	Electric & Gas				
California	Electric & Gas	Electric & Gas			Electric & Gas		Yes
Colorado	Electric & Gas				Electric only		
Connecticut	Electric, Gas, & Water	Electric & Gas	Gas only	Electric & Gas			Yes
Delaware	Electric, Gas, & Water						
District of Columbia	Electric & Gas	Electric only					
Florida	Electric & Gas			Gas only	Electric only		Yes
Georgia	Electric & Gas	Gas only		Gas only	Electric only	Gas only	Yes
Hawaii	Electric only	Electric only			Electric only		Yes
Idaho	Electric only	Electric only					
Illinois	Gas & Water	Gas only		Electric & Gas		Electric only	Yes
Indiana	Electric, Gas, & Water	Gas only	Electric only		Gas only		
Iowa	Gas only			Gas only	Electric only		
Kansas	Gas only		Electric only	Gas only			
Kentucky	Electric & Gas		Electric & Gas	Gas only			Yes
Louisiana	Electric only		Electric only		Electric only	Electric & Gas	Yes
Maine	Electric, Gas, & Water	Electric only		Gas only	Gas only		Yes
Maryland	Electric & Gas	Electric & Gas					
Massachusetts	Electric & Gas	Electric & Gas	Electric & Gas		Gas only		
Michigan	Gas only	Gas only					Yes

Table 1 continued

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Minnesota	Electric & Gas	Electric & Gas					Yes
Mississippi	Electric & Gas		Electric & Gas	Electric only		Electric & Gas	Yes
Missouri	Gas & Water			Gas only			
Montana	Electric & Gas		Gas only				
Nebraska	Gas only			Gas only			
Nevada	Gas only	Gas only	Electric only				
New Hampshire	Electric, Gas, & Water			Gas only	Electric & Gas		
New Jersey	Electric, Gas, & Water	Gas only					
New Mexico							Yes
New York	Gas & Water	Electric & Gas	Gas only	Electric & Gas	Electric & Gas		Yes
North Carolina	Gas & Water	Gas only	Electric only				
North Dakota	Electric only			Gas only	Electric only		Yes
Ohio	Electric, Gas, & Water	Electric only	Electric only	Gas only	Electric only		
Oklahoma	Electric only		Electric only	Electric & Gas		Gas only	
Oregon	Electric & Gas	Electric & Gas	Electric & Gas				Yes
Pennsylvania	Electric, Gas, & Water			Gas only			Yes
Rhode Island	Electric & Gas	Electric & Gas					Yes
South Carolina	Electric only		Electric only			Gas only	
South Dakota	Electric only						
Tennessee	Gas only	Gas only		Gas only		Gas only	Yes
Texas	Electric & Gas			Gas only		Gas only	
Utah	Gas only	Gas only					Yes
Vermont				Gas only			
Virginia	Electric & Gas	Gas only		Gas only	Electric only		
Washington	Gas only	Electric & Gas			Electric & Gas		
West Virginia	Electric only						
Wisconsin				Gas only			Yes
Wyoming	Electric only	Gas only	Electric & Gas	Electric & Gas			Yes

[1] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers

A cost tracker is a mechanism for expedited recovery of specific utility cost (e.g., outside of a rate case). Balancing accounts are typically used to track unrecovered costs. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are more practical than rate cases for addressing particular costs. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and materially impact utility risk. Other volatile expenses that are sometimes addressed with trackers include those for pensions, severe storms, and uncollectible bills.

A second use of trackers is for costs incurred due to policies of government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to consider the impact of their policies on customer bills.

Trackers are also used to compensate utilities for costs that are rapidly rising and don't otherwise trigger new revenue, whether or not they are volatile or mandated. This encourages needed expenditures and reduces risk and the frequency of rate cases. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in large measure to their rapid growth include those for health care.

Trackers for some costs have multiple rationales. DSM expenses, for example, are often sizable and sometimes grow rapidly.[1] Utility DSM programs are often mandated. Additionally, DSM can slow growth in the average use of power and reduce the need for plant additions, important sources of earnings growth for utilities. Tracking DSM expenses helps to balance utility incentives to embrace DSM.

Capital cost trackers typically address the accumulating depreciation, return on asset value, and taxes that result from the capex.[2] Capital costs can qualify for tracker treatment on several grounds. Major plant additions are volatile. Capex might be necessitated by highway construction or changes in government safety, reliability, or environmental standards. Capex is sometimes large enough to cause brisk cost growth that would otherwise occasion frequent rate cases.

An early use of capital cost trackers in the electric utility industry was to address construction costs of large power plants. These plants can take years to construct. An allowance in rates for a return on funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery of the allowance strains utility cash flow, increases financing expenses, and induces more rate "shock" when the value of the plant and construction financing is finally added to the rate base.

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[1] This survey only documents capital cost trackers. Trackers for DSM expenses are ubiquitous so that there is less need for documentation.

[2] Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Many commissions have addressed these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers have often been used in lieu of frequent rate cases to obtain CWIP recovery.

Capital costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for large generation units, and construction of specific assets usually takes less than a year. However, the capex can still be sizable and doesn't automatically trigger new revenue when completed. A tracker for accelerated modernization costs can help a company modernize its grid and improve its services without frequent rate cases.

Capital costs of generation emissions controls are often accorded tracker treatment. These controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities typically become used and useful each year over a series of years.

There are varied treatments of costs in approved capital trackers. Regulators often approve tracked capex budgets in advance, usually after considerable deliberation. Procedures for reviewing the need for generation plant additions are especially well established. Once a budget is set, the treatment of variances between actual and budgeted cost becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. Utilities are also permitted sometimes to share in the benefits of capex underspends. The prudence of tracked capex is often subject to a final review when the cost is added to rate base, a step that usually occurs in the next rate case.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are numerous and continue to grow. This is the most widely used Altreg tool in the United States. For electric utilities, trackers for emissions controls, generation capacity, advanced metering infrastructure, and general system modernization have been especially common in recent years. Trackers for gas distributors typically address the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common for accelerated modernization.

Figure 2: Recent Capital Cost Tracker Precedents by State: Energy Utilities

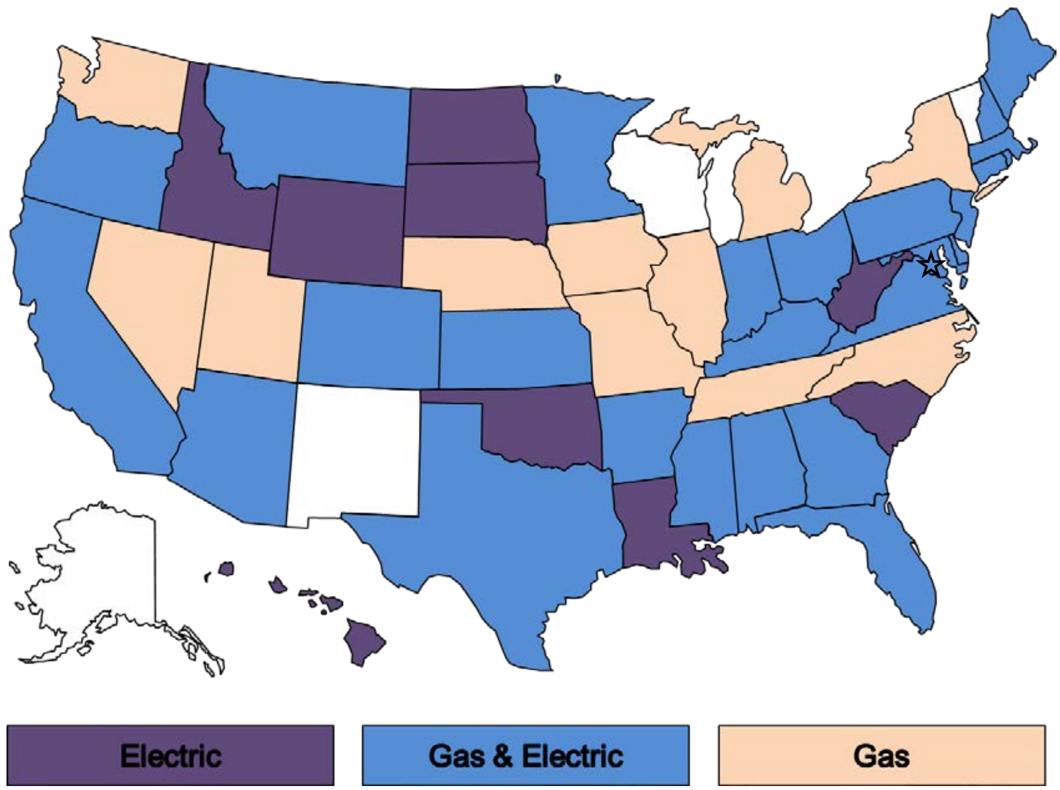


Figure 3: Recent Capital Cost Tracker Precedents by State: Water Utilities

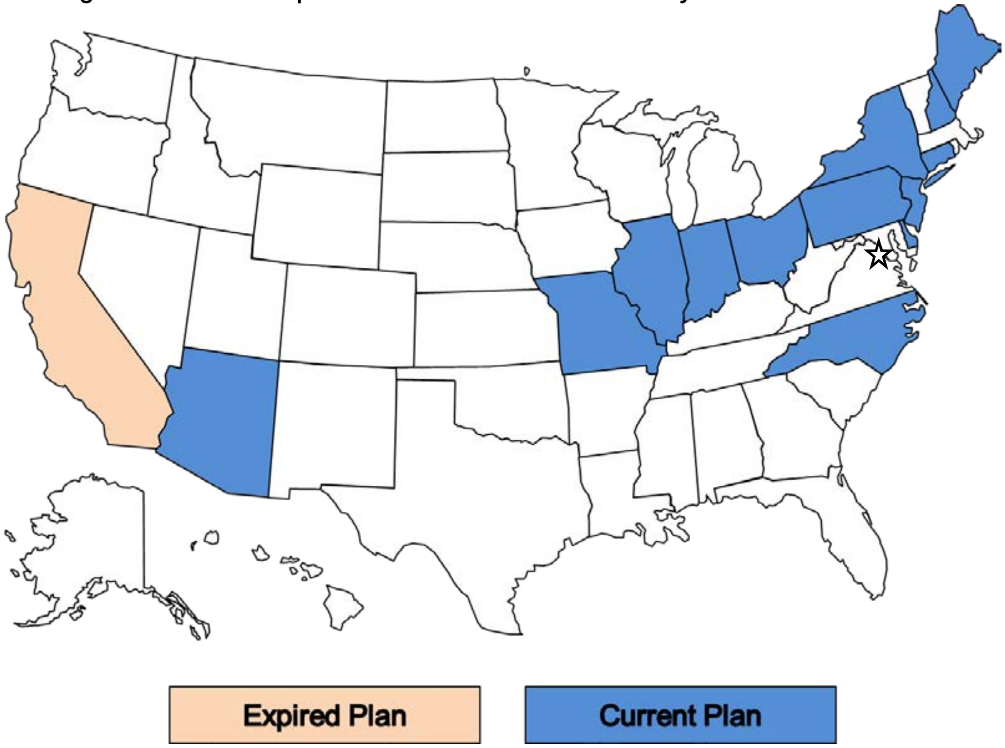


Table 2

Recent Capital Cost Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	Arkansas Oklahoma Gas	Gas	Act 310 Surcharge	Relocations of pipelines mandated by government agencies	Docket 12-088-U (July 2013)
AR	Arkansas Oklahoma Gas	Gas	System Safety Enhancement Rider	Replacement of bare steel mains, mains on low pressure systems, mains that are subject of an advisory notice by government that company deems to be unsatisfactory	Docket 13-078-U (July 2014)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket 10-108-U (March 2011)
AR	Empire District Electric	Electric	Alternative Generation Environmental Recovery Rider	Environmental	Docket 15-010-U (August 2015)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket 10-109-U (August 2011)
AR	SourceGas Arkansas	Gas	At-Risk Meter Relocation Program Rider	Installation of new services for meters relocated due to motor vehicle collision risk	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Main Replacement Program Rider	Replacement of bare steel and coated steel mains, mains that are subject of an advisory notice by government that company deems to be unsatisfactory, and associated services	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Act 310 Surcharge	Bare steel and cast iron pipeline replacement, in-line inspection project, emissions controlling catalysts for compressor station engines, greenhouse gas monitoring of some regulator stations, highway relocation projects	Docket 13-072-U (April 2014)
AR	SWEPCO	Electric	Alternative Generation Recovery Rider	New generation	Docket 09-008-U (November 2009)
AR	SWEPCO	Electric	Rider Environmental Compliance Surcharge	Environmental	Docket 15-021-U (October 2015)
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket E-01345A-08-0172
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket E-01345A-11-0224 (May 2012)
AZ	Arizona Public Service	Electric	Four Corners Rate Rider Surcharge	Generation	Docket E-01345A-11-0224 (December 2014)
AZ	Arizona Water Company	Water	Arsenic Cost Recovery Mechanism	Investments to reduce arsenic in water supply	Various (operating regions have separate decisions approving ACRMs)
AZ	Arizona Water Company - Eastern Group	Water	System Improvement Benefits Mechanism	Replacement of leak prone mains and related services, meters, and hydrants, replace meters that do not have lead free brass, other replacements for mains, services, meters, and hydrants that are at the end of their useful life	Decision 73938 (June 2013)
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket G-01551A-10-0458 (January 2012)
AZ	Tucson Electric Power	Electric	Environmental Compliance Adjustor	Miscellaneous environmental projects	Decision 73912 (June 2013)
CA	Pacific Gas & Electric	Electric	Smart Grid Memorandum Account	Smart grid projects that received DOE matching funds	Decision 09-09-029 (September 2009)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	Pacific Gas & Electric	Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement	Decision 13-03-032 (March 2013)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	Energy Storage Balancing Account	Projects to store solar energy	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced metering infrastructure project	Decision 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CA	Southern California Gas	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CO	Black Hills Colorado Electric	Electric	Transmission Cost Adjustment Rider	Transmission projects	Docket 09-014E, Decision C09-0271 (March 2009)
CO	Black Hills Colorado Electric	Electric	Clean Air Clean Jobs Act Rider	Gas-fired generation	Docket 14AL-0393E, Decision C14-1504 (December 2014)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket 07A-339E, Decision C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket 10-AL-963G (August 2011)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
CO	Public Service Company of Colorado	Electric	Clean Air Clean Jobs Act Rider	Miscellaneous environmental projects including gas-fired generation, scrubbers	Proceeding 14A-680E, Decision C15-0292 (March 2015)
CO	Rocky Mountain Gas	Gas Transmission	System Safety and Integrity Rider	TIMP, DIMP, and other safety regulatory compliance projects	Docket 13AL-0046G, Decision R14-0114 (February 2014)
CT	Aquarion Water Company of Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-06-21WI01 (December 2008)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket 12-07-06 (January 2013)
CT	Connecticut Natural Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Connecticut Natural Gas	Gas	DIMP True-Up Mechanism	Cast iron and bare steel main replacement	Docket 13-06-08; (January 2014)
CT	Connecticut Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-10-15WI01 (March 2009)
CT	Southern Connecticut Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Torrington Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	United Water Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	Yankee Gas Services	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
DC	Potomac Electric Power	Electric	Underground Project Charge	Undergrounding of specific feeders	Formal Case 1116 (November 2014)
DC	Washington Gas Light	Gas	Plant Recovery Adjustment	Remediation/replacement of mechanical couplings	Formal Case 1027 (December 2009)
DC	Washington Gas Light	Gas	Accelerated Pipe Replacement Plan Adjustment	Replacement of cast iron mains, bare steel mains and services and "black plastic" services	Formal Case 1115 (January 2015)
DE	Artesian Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-474 (December 2001)
DE	Delmarva Power & Light	Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 12-546 (October 2013)
DE	Delmarva Power & Light	Electric	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 13-115 (August 2014)
DE	Sussex Shores Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-470 (December 2001)
DE	Tidewater Utilities	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 03-210 (May 2003)
DE	United Water Delaware	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-481 (December 2001)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Florida City Gas	Gas	Safety and Access Verification Expedited Program	Replacement of unprotected steel mains, relocation of certain gas mains in rear lot easements	Docket 150116-GU (September 2015)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket 120015-EI (December 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 930613-EI (January 1994)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 050078-EI (September 2005)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Generation Base Rate Adjustment	Generation	Docket 130208 (November 2013)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 960688-EI (August 1996)
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 29950 as STRIDE tracker in 2009
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Surcharge	Pre-1985 plastic mains and services replacement, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility	Docket 8516-U and 29950 (October 2009 and August 2013)
GA	Atmos Energy (now Liberty Utilities)	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket 12509-U (December 2000)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Docket 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket 27800, Senate Bill 31
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
IA	Black Hills Energy	Gas	System Safety Maintenance Adjustment	Replacement of steel and pvc pipe, relocations mandated by local governments	Docket RPU-2012-0004 (March 2013)
ID	PacifiCorp	Electric	Energy Cost Adjustment Mechanism	Lake Side II generation facility	Case PAC-E-13-04 (October 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
IL	Ameren Illinois	Gas	Rider Qualifying Infrastructure Plant	Replacement of prone to leak distribution and transmission pipe, installation of AMI and communications infrastructure, replacing or installing transmission or distribution facilities to establish over-pressure protection, replacement of difficult to locate mains and services, replacement of high pressure transmission pipelines without a recorded maximum allowable operating pressure, replacements to facilitate an upgrade from a low pressure system to a high pressure system	Docket 14-0573 (January 2015)
IL	Consumers Illinois Water Company (Kankakee, Vermilion, Woodhaven Districts)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-0561 (December 2001)
IL	Illinois-American Water (Chicago Metro Division)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 09-0251 (March 2010)
IL	Illinois-American Water (Single Tariff Pricing Zone)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 04-0336 (December 2004)
IL	Northern Illinois Gas	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast iron pipe, non-cast iron pipe, and copper services; relcoation of meters from inside customers' premises; upgrading of system from low pressure to medium pressure; replacement or installation of regulator stations, regulators, valves and associated facilities to establish over-pressure protection	Docket 14-0292 (July 2014)
IL	Peoples Gas Light & Coke	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast and ductile iron, relcoation of meters from inside customers' premises, upgrading of system from low pressure to medium pressure, replacement of high pressure transmission pipelines at higher risk of failure or lacking records, installation of regulator stations to establish over-pressure protection	Docket 13-0534 (January 2014)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Miscellaneous environmental projects	Cause 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket 43114 (November 2007)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Miscellaneous environmental projects	Cause 43636 (June 2009)
IN	Indiana Water Service	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42743 DSIC-1 (December 2004)
IN	Indiana-American Water	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42351 DSIC-1 (February 2003)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Cause 42170 (November 2002)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Miscellaneous environmental projects	Cause 42150 (November 2002)
IN	Northern Indiana Public Service	Electric	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of aging infrastructure, economic development	Cause 44370 and 44371 (February 2014)
IN	Northern Indiana Public Service	Gas	Distribution System Improvement Charge	Gas system deliverability and system integrity projects, rural main extensions	Cause 44403 TDSIC 1 (January 2015)
IN	Utility Center Inc.	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 42416 DSIC-1 (June 2003)
IN	Vectren Energy Delivery (Indiana Gas and Southern Indiana Gas & Electric)	Gas	Compliance and System Improvement Adjustment	System and pressure improvements, storage operations, instrumentation and communications equipment, public improvement projects, service replacements, and economic development	Cause 44429 (August 2014)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 08-AQLG-852-TAR (July 2008)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 09-MDWE-722-TAR (May 2009)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocations	Docket 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Docket 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Projects to be determined in subsequent filings to Commission	Docket U-30689 and U-32779 (October 2010 and June 2014)
LA	Entergy Gulf States Louisiana	Electric	Formula Rate Plan-3	Acquisition of generating facility, new generating facility or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32707 (December 2013)
LA	Entergy Louisiana	Electric	Formula Rate Plan 7	Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32708 and 31971 (January 2014 and April 2012)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Bay State Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, service tie-ins, encroached pipe, and meters	DPU 14-134
MA	Berkshire Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron mains and associated services, encroached pipe, and meter sets composed of non-cathodically protected steel, cast iron or copper	DPU 14-131
MA	Fitchburg Gas & Electric Light	Gas	Gas System Enhancement Adjustment Factor	Replacement of cast main and unprotected steel mains and services and encroached pipe	DPU 14-130

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MA	Massachusetts Electric	Electric	Net CapEx Factor	Potentially all distribution investments	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Massachusetts Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-132
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	New England Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-133
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	Smart Grid Adjustment Factor	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MD	Baltimore Gas & Electric	Electric	Electric Reliability Investment Surcharge	Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits	Case 9326 (December 2013)
MD	Baltimore Gas & Electric	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel mains and services, cast iron mains, copper services, and pre-1982 plastic "Ski Bar" risers	Case 9331 (January 2014)
MD	Columbia Gas of Maryland	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel and cast iron mains and bare steel services	Case 9332 (August 2014)
MD	Delmarva Power & Light	Electric	Grid Resiliency Charge	Feeder hardening	Case 9317 (September 2013)
MD	Potomac Electric Power	Electric	Grid Resiliency Charge	Feeder hardening	Case 9311 (July 2013)
MD	Washington Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program Rider	Replacement of bare and unprotected steel mains and services, targeted copper and pre-1975 plastic services, mechanically coupled pipe main and services, and cast iron mains	Case 9335 (May 2014)
ME	Central Maine Power	Electric	Customer Relationship Management & Billing Rate Adjustment	Customer relationship management & billing system replacement	Docket 2015-00040 (October 2015)
ME	Maine Water Company	Water	Water Infrastructure Charge	Replacement of stationary physical plant assets needed to operate a water system	Various orders separately issued for operating divisions
ME	Northern Utilities	Gas	Targeted Infrastructure Recovery Adjustment	Cast iron, bare steel, and unprotected coated steel mains and services replacements, replacement of farm tap regulators	Docket 2013-00133 (December 2013)
MI	Consumers Energy	Gas	Enhanced Infrastructure Replacement Program	Cast iron replacements	Case U-17643 (January 2015)
MI	Michigan Consolidated Gas (now DTE Gas)	Gas	Infrastructure Recovery Mechanism	Replacement of cast iron mains, replacement of indoor meters with outdoor meters, pipeline integrity projects designed to comply with federal and state safety standards	Case U-16999 (April 2013)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 and U-17824 (January 2011 and June 2015)
MN	Interstate Power & Light	Electric	Renewable Energy Recovery Adjustment	Renewable generation	Docket M-10-312 (December 2013)
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Miscellaneous environmental projects	Docket M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Rider for Boswell Unit 4 Emission Reduction	Miscellaneous environmental projects	Docket M-12-920 (November 2013)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Miscellaneous environmental projects	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-06-1103 (November 2006)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket M-08-261 (November 2008)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Miscellaneous environmental projects	Docket M-09-847 (November 2009)
MN	Otter Tail Power	Electric	Renewable Resource Cost Recovery Rider	Renewable generation	Docket M-08-119 (August 2008)
MN	Otter Tail Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-09-881 (January 2010)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Case GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2007-0208 (July 2007)
MO	Missouri American Water	Water	Infrastructure System Replacement Surcharge	Replacement of mains, associated valves and hydrants, main cleaning and relining projects	Case WO-2004-0116 (December 2003)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2009-0355 (February 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MS	Atmos Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new industrial customers for economic development	Docket 2013-UN-23 (July 2013)
MS	Centerpoint Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new commercial and industrial customers for economic development	Docket 13-UN-214 (October 2013)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Miscellaneous environmental projects	Docket 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket D2012.3.25 (November 2012)
NC	Aqua North Carolina	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-218, Sub 363 (May 2014)
NC	Aqua North Carolina	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-218, Sub 363 (May 2014)
NC	Carolina Water Service	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-354, Sub 336 (March 2014)
NC	Carolina Water Service	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-354, Sub 336 (March 2014)
NC	Piedmont Natural Gas	Gas	Integrity Management Rider	Investments driven by federal pipeline safety and integrity requirements	Docket G-9, Sub 631 (December 2013)
ND	Montana-Dakota Utilities	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-85 (December 2013)
ND	Montana-Dakota Utilities	Electric	Generation Resource Recovery Rider Tariff	New Generation	Case PU-14-108 (August 2014)
ND	Northern States Power- MN	Electric	Transmission Cost Rider	Transmission projects	Case PU-12-813 (February 2014)
ND	Northern States Power- MN	Electric	Renewable Energy Rider	North Dakota based renewable generation	Case PU-12-813 (February 2014)
ND	Otter Tail Power	Electric	Renewable Resource Rider	Renewables	Case PU-06-466 (May 2008)
ND	Otter Tail Power	Electric	Transmission Facility Cost Recovery Tariff	Transmission investments required to serve retail customers	Case PU-11-682 (April 2012)
ND	Otter Tail Power	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-84 (December 2013)
NE	Black Hills Nebraska Gas Utility	Gas	Infrastructure System Replacement Recovery Charge	Non-revenue increasing projects to replace existing assets	Application NG-0074
NE	SourceGas Distribution	Gas	Pipeline Replacement Charge	Projects entering service before May 2014 that are installed to comply with safety requirements as replacements for existing facilities, projects that will extend the useful life of existing assets or enhance pipeline integrity, facility relocations	Application NG-0072 (June 2013)
NE	SourceGas Distribution	Gas	System Safety and Integrity Rider	Projects entering service after April 2014 that comply with federal regulations including transmission and distribution integrity management plans or are facility relocations costing $20,000 or more	Application NG-0078 (October 2014)
NH	Aquarion Water of New Hampshire	Water	Water Infrastructure and Conservation Adjustment Charge	Projects to upgrade or replace non-revenue producing assets including main, valve, and hydrant replacement, main cleaning and relining, and non-reimbursable relocations	Docket DW 08-098 (September 2009)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Miscellaneous environmental projects	DE 11-250 (April 2012)
NH	Public Service Company of New Hampshire	Electric	Reliability Enhancement Plan	Reliability improvements	DE 09-035, DE 11-250, and DE 14-238 (June 2015)
NJ	Elizabethtown Gas	Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort	System hardening	Docket GO13090826 (July 2014)
NJ	New Jersey American Water	Water	Distribution System Improvement Charge	Incremental non-revenue water main replacement, rehabilitation, or mandated relocation projects, service line replacements, valve and hydrant replacement	Docket WR12070669 (October 2012)
NJ	New Jersey Natural Gas	Gas	New Jersey Reinvestment in System Enhancement	Storm hardening projects	Docket GR13090828 (July 2014)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket EO09020125 (August 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Dockets GO09010050, EO11020088, GO10110862 (April 2009 and July 2011)
NJ	Public Service Electric and Gas	Electric & Gas	Energy Strong Adjustment Mechanism	Electric: substation flood mitigation, gird reconfiguration strategies, and smart grid; Gas: Metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas	Docket EO13020155, GO13020156 (May 2014)
NJ	South Jersey Gas	Gas	Storm Hardening and Reliability Program	Replacement of low pressure mains and services with high pressure mains and services, removal of regulator stations, installation of excess flow valves in coastal areas	Docket GO13090814 (August 2014)
NJ	United Water New Jersey	Water	Distribution System Improvement Charge	Repair, replace, and/or clean mains, replace valves, hydrants, and service lines	Docket WR12080724 (October 2012)
NV	Southwest Gas	Gas	Gas Infrastructure Replacement Mechanism	Early vintage pipe replacements, conversion of master metered customers to individual meters	Docket 14-10002 (December 2014)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
NY	Corning Natural Gas	Gas	Safety and Reliability Charge	Replacement of leak prone pipe and ancillary costs to maintain a safe and reliable system	Case 11-G-0280 (October 2015)
NY	Keyspan Energy Long Island	Gas	Leak Prone Pipe Surcharge	Accelerated leak prone pipe removal program	Case 12-G-0214 (December 2014 and March 2015)
NY	Long Island American Water	Water	System Improvement Charge	Iron removal, storage tank rehabilitiation, suction well rehabilitation at selected plants, customer information system	Case 11-W-0200 (March 2012)
NY	United Water New Rochelle	Water	Long Term Main Renewal Project	Cleaning and relining of mains	Case 99-W-0948 (August 2000)
NY	United Water New York	Water	Underground Infrastructure Renewal Program	Replacement of infrastructure including mains, valves, services, meters, and hydrants	Case 06-W-0131 (December 2006)
NY	United Water New York	Water	New Water Supply Source Surcharge	Projects to provide new sources of water in the short and long term	Case 06-W-0131 (December 2006)
OH	Aqua Ohio	Water	System Infrastructure Improvement Surcharge	Replacement of service lines, mains, hydrants, valves, main extensions to resolve documented water supply problems	Case 04-1824-WW-SIC (March 2005)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case 10-388-EL-SSO (August 2010)
OH	Columbia Gas	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010)
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services and faulty risers	1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Cases 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Duke Energy Ohio	Electric	Distribution Capital Investment Rider	Distribution capital investments not recovered through other trackers	Case 14-841-EL-SSO (April 2015)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Bare steel and cast iron pipelines & faulty riser replacements	Case 08-169-GA-ALT (October 2008)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMR	Cases 07-0829-GA-AIR and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010)
OH	Ohio American Water	Water	System Improvement Charge	Non-revenue producing service lines, hydrants, mains, valves, main extensions that improve supply problems, main cleaning	Case 05-577-WW-SIC (August 2005)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net distribution capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Cases 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause PUD 20080387, Order 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	System Reliability Rider	Grid resiliency projects	Cause PUD 201300202 (January 2014)
OK	Public Service Company of Oklahoma	Electric	Advanced Metering Infrastructure Tariff	Advanced metering infrastructure deployment	Cause PUD 201300217 (April 2015)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, transmission integrity management program, distribution integrity management program	Docket UM 1406, Order 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	Lake Side 2 Tariff Rider	Generation	Docket UE 263, Order 13-474 (December 2013)
OR	PacifiCorp	Electric	M2O Transmission Rider	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Orders 12-493 and 13-195 (December 2012 and May 2013)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	Columbia Gas	Gas	Distribution System Improvement Charge	Replacement of cast iron, bare steel, and first generation plastic mains and services, install excess flow valves, install or relocate automated meters, and replace risers, meter bars, and service regulators	P-2012-2338282 (March 2013)
PA	Columbia Water Company	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00021979
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket M-2009-2123948 (April 2010)
PA	Equitable Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2342745 (July 2013)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket M-2009-2123944 (April 2010)
PA	PECO	Electric	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations	Docket P-2015-2471423 (October 2015)
PA	PECO	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2347340 (September 2015)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania-American Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-000961031 (August 1996)
PA	Peoples Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344596 (May 2013)
PA	Peoples TWP	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344595 (May 2013)
PA	Philadelphia Gas Works	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2012-2337737 (April 2013)
PA	Philadelphia Surburban Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00961035 (August 1996)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket M-2009-2123945 (January 2010)
PA	PPL Electric Utilities	Electric	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires)	Docket P-2012-2325034 (May 2013)
PA	UGI Central Penn Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2398835 (September 2014)
PA	UGI Penn Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2397056 (September 2014)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Previous accelerated capital replacement program investments plus main and service replacements and reliability investments	Docket 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Miscellaneous environmental projects	Docket EL11-001
SD	Black Hills Power	Electric	Phase in plan rate	Gas-fired generation	Docket EL12-062 (September 2013)
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL07-026 (January 2009)
SD	Northern States Power- MN	Electric	Transmission Cost Recovery Tariff	Transmission	Docket EL07-007 (January 2009)
SD	Northern States Power- MN	Electric	Infrastructure Rider	Generation	Docket EL 12-046 (April 2013)
SD	Otter Tail Power	Electric	Transmission Cost Recovery Tariff	Retail sales portion of specific transmission projects	Docket EL 10-015 (November 2011)
SD	Otter Tail Power	Electric	Environmental Quality Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL 14-082 (December 2014)
TN	Piedmont Natural Gas	Gas	Integrity Management Rider	Distribution and transmission integrity management planning as required by the US Department of Transportation	Docket 13-00118 (May 2014)
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Gas Utilities Dockets 9615 and 10640
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket 35620 (August 2008)
TX	Centerpoint Energy Houston Electric	Electric	Distribution Cost Recovery Factor	Change in net distribution rate base since last rate case	Docket 44572 (August 2015)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Miscellaneous environmental & reliability projects	Docket PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Miscellaneous environmental projects	Case PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case PUE-2011-00049 (November 2011)
VA	Roanoke Gas Company	Gas	SAVE Rider	Replacement of cast iron mains, bare steel mains and services and pre-1973 plastic pipe	Case PUE-2012-00030 (August 2012)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case PUE-2011-00073 (March 2012)
VA	Virginia Electric Power	Electric	Rider BW	Brunswick County Power Station (natural gas combined cycle generating station)	Case PUE-2012-00128 (August 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
VA	Virginia Natural Gas	Gas	SAVE Rider	Replacement of first generation plastic mains, cast and wrought iron mains, bare and ineffectively coated steel mains, and service lines installed prior to 1971	Case PUE-2012-00012 (June 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and pre-1975 plastic services	Cases PUE-2010-00087 and PUE-2012-00096 (April 2011 and November 2012)
WA	Cascade Natural Gas	Gas	Pipeline Replacement Program Cost Recovery Mechanism	Replacement of bare steel and poorly coated pipelines and distribution systems	Docket PG-131838 (October 2013)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WV	Monongahela Power	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Potomac Edison	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20003-123-ET-12 (November 2012)

III. Relaxing the Link Between Revenue and System Use

Policymakers are increasingly interested in relaxing the link between the revenues utilities realize, and the kWh and kW of system use by customers. This reduces the financial attrition that results from slowing growth in system use (given legacy rate designs) more efficiently than frequent rate cases. In addition, utilities have more incentive to embrace DSM. Three approaches to relaxing the revenue/usage link are well established: lost revenue adjustment mechanisms (“LRAMs”), revenue decoupling, and fixed/variable pricing.

A. Lost Revenue Adjustment Mechanisms

LRAMs keep utilities whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also DG). Recovery usually is effected through a special rate rider. Estimates of load losses are needed.

LRAMs encourage utilities to embrace DSM that is eligible for LRAM treatment. They do not provide recovery for the revenue impact of external forces, like DSM programs managed by independent agencies, which slow load growth. Estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. When usage charges are high, the utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers.

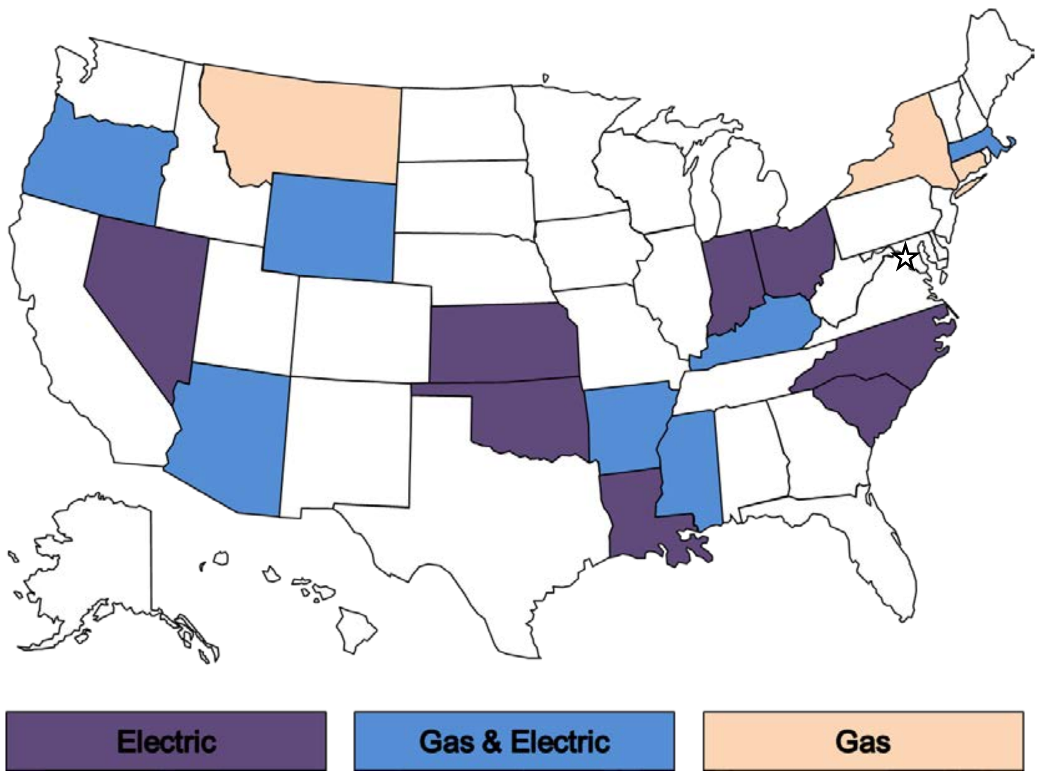
Precedents for LRAMs are detailed in Table 3 and Figure 4 below.[3] LRAMs are currently the most popular means of relaxing the link between revenue and system use in the US electric utility industry. Since our 2013 survey, LRAMs have been adopted for electric utilities in Arizona, Louisiana, and Mississippi. A few utilities have LRAMs that address DG. LRAMs are less popular for gas distributors since the declining average use they have typically experienced for many years is due chiefly to external forces that LRAMs don’t address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

B. Revenue Decoupling

Revenue decoupling adjusts a utility’s rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism (“RDM”) and a revenue adjustment mechanism (“RAM”). The RDM tracks variances between actual and allowed revenue and adjusts rates to reduce them. The RAM escalates allowed revenue to provide relief for growing cost pressures.

[3] Some mechanisms similar to LRAMs are excluded from this survey.

Figure 4: Current LRAMs by State



RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustment that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs. RDMs also vary in terms of the services for which revenues are pooled for true up purposes. In some plans all services are placed in the same "basket." Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

Table 3

Current LRAM Precedents[1]

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket 07-075-TF, Order 26
AR	SourceGas Arkansas	Gas	June 2011	Docket 07-078-TF, Order 26
AR	Southwestern Electric Power	Electric	June 2011	Docket 07-082-TF, Orders 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket E-01345A-11-0224, Decision 73l83
AZ	Tucson Electric Power	Electric	June 2013	Docket E-01933A-12-0291; Decision 73912
AZ	UNS Electric	Electric	September 2013	Docket E-04204A-12-0504; Decision 74235
AZ	UNS Gas	Gas	May 2012	Docket G-04204A-11-0158 Decision 73142
CT	Southern Connecticut Gas	Gas	August 1995	Docket 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Causes 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Cases 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case 2004-00389
KY	Kentucky Power	Electric	December 1995	Case 95-427
KY	Kentucky Utilities	Electric	May 2001	Case 2000-0459
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case 93-150
LA	Cleco Power	Electric	October 2014	Docket R-31106
LA	Entergy Gulf States Louisiana	Electric	October 2014	Docket R-31106
LA	Entergy Louisiana	Electric	October 2014	Docket R-31106
LA	Southwestern Electric Power	Electric	October 2014	Docket R-31106
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128

Table 3 (cont'd)

State	Company	Services	Approval Date	Case Reference
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MS	Atmos Energy	Gas	August 2014	Docket 2014-UA-017
MS	Centerpoint Energy	Gas	August 2014	Docket 2014-UA-007
MS	Entergy Mississippi	Electric	September 2014	Docket 2009-UN-064
MS	Mississippi Power	Electric	March 2015	Docket 2014-UN-10
MT	Montana-Dakota Utilities	Gas	October 2006	Docket D2005.10.156; Order 6697c
NC	Duke Energy Carolinas	Electric	February 2010	Docket E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket E-22, Sub 464
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
NY	Keyspan Long Island	Gas	December 2009	Case 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case 06-G-1185; Currently effective for all customers not in RDM
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket 08-1094-EL-SSO
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007 and August 2012	Dockets 06-0091-EL-UNC and 11-4393-EL-RDR; Effective for classes not included in RDM
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket 08-935-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause PUD 200900196; Order 572836
OR	Cascade Natural Gas	Gas	April 2006	Order 06-191; UG 167 Effective for classes not included in RDM
OR	Portland General Electric	Electric	September 2001	Order 01-836; UE 79 Effective for classes not included in RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Duke Energy Carolinas	Electric	January 2010	Docket 2009-226-E Order 2010-79
SC	Progress Energy Carolinas	Electric	June 2009	Docket 2008-251-E Order 2009-373
SC	South Carolina Electric & Gas	Electric	July 2010	Docket 2009-261-E, Order 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Dockets 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket 20004-65-ET-06

[1] LRAMs listed here include only those mechanisms that compensate utilities for actual revenues lost due to DSM and DG.

The great majority of decoupling systems have a RAM since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. Utilities that do not have RAMs in their decoupling systems often file frequent rate cases or are allowed to use capital cost trackers to address attrition. The more important issue in a proceeding to consider decoupling is therefore the design of the RAM rather than the need for one.

Most RAMs escalate allowed revenue only for customer growth. Escalation for customer growth is sensible because it is an important driver of cost and also highly correlated with other drivers such as peak demand. The need for rate cases is thereby reduced but is rarely eliminated since cost has other drivers such as input price inflation. When RAMs are escalated only for customer growth, utilities usually retain the freedom to file rate cases to address other cost factors and often do. Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and provide a foundation for a multiyear rate plan.

Revenue decoupling compensates utilities for declining average use even if it is driven in part by external forces such as independently administered DSM programs. The lost revenue disincentive is removed for a wide array of utility initiatives to encourage DSM without requiring load impact calculations or rate designs that discourage DSM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster DSM. This makes environmental intervenors strong supporters of decoupling. Controversy over billing determinants in rate cases with future test years is reduced.

Revenue decoupling is a popular means of relaxing the link between a utility's revenue and customers' kWh consumption. States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Revenue decoupling precedents in the United States and Canada are detailed in Table 4. In the electric utility industry, decoupling has been favored in states that strongly support DSM. Since our 2013 survey, decoupling has been adopted for electric utilities in Connecticut, Maine, Minnesota, and Washington state. Decoupling is the most widespread means of relaxing the revenue/usage link for gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been driven chiefly by external forces. Table 4 indicates the kinds of RAMs chosen in approved decoupling systems. Note that RAMs for electric utilities are frequently broad-based.

C. Fixed/Variable Pricing

Fixed/variable pricing is an approach to rate design that uses fixed charges (charges that do not vary with the actual sales volume or peak demand) to compensate utilities for fixed costs of service. For residential and small commercial services, customer charges (a flat monthly fee per customer) are the most common fixed charge used. Base revenue thus tends to grow at the gradual pace of customer growth. A *straight* fixed/variable ("SFV") rate design recovers *all* base revenue through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed/variable pricing.

Figure 5a: Electric Revenue Decoupling by State

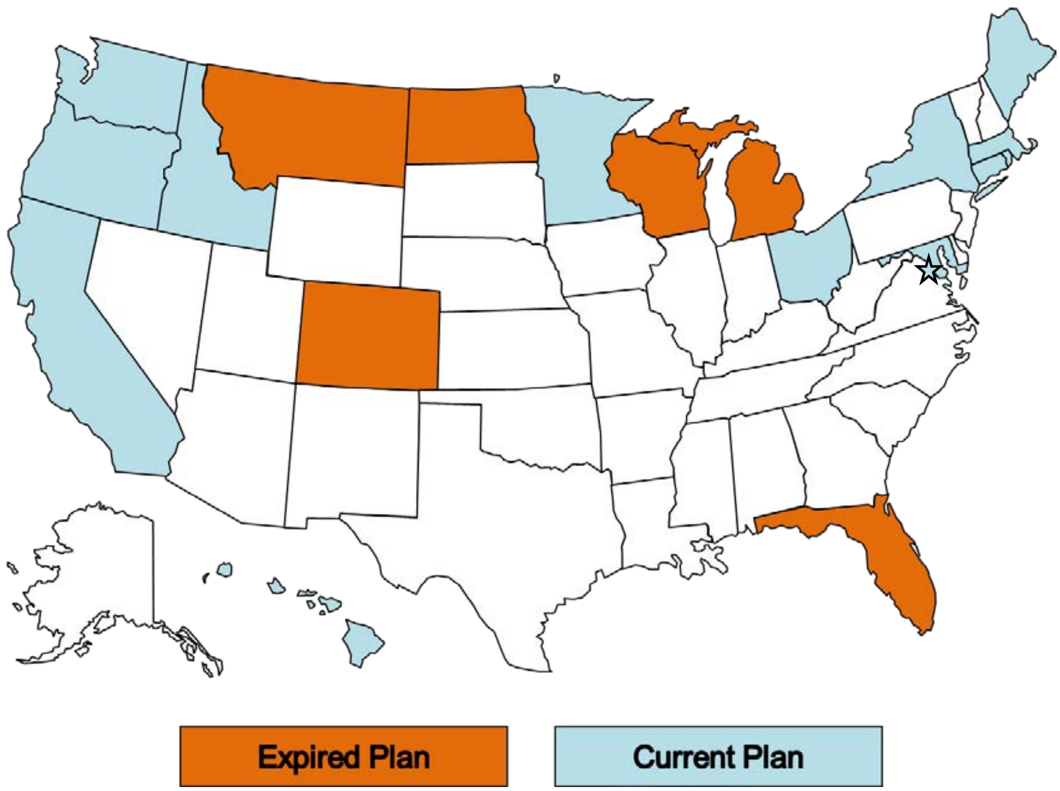


Figure 5b: Gas Revenue Decoupling by State

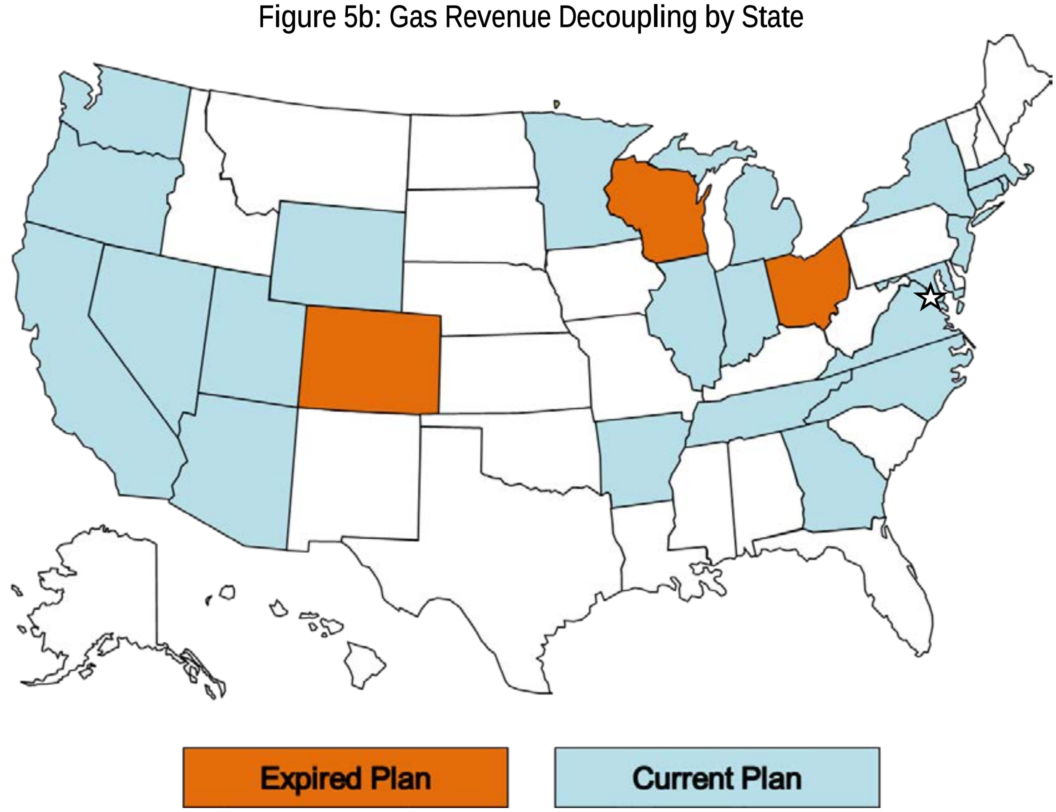


Table 4

Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current					
United States					
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2016	Stairstep	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2012-2015	Stairstep	Decision 13-05-010
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2012-2015	Stairstep	Decision 13-05-010
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2011-2015	Customers	Cause 44019
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2011-2015	Customers	Cause 44019
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	New England Gas	Gas	2011-open	Customers	DPU 10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
United States (cont'd)					
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999
MI	Michigan Gas Utilities	Gas	2015-open	No RAM	Case U-17273
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-2016	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-2014	Revenue per Customer Stairstep through 2014, Customers After 2014	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0715
NY	New York State Electric & Gas	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0716
NY	Niagara Mohawk	Gas	2013-2016	Optional Revenue per Customer Stairstep	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2016	Optional Stairstep	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0717
NY	Rochester Gas & Electric	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0718
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Cascade Natural Gas	Gas	2013-2015	Customers	Order 13-079
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2013-2015	Customers	Case PUE-2012-00013
VA	Virginia Natural Gas	Gas	2013-2016	Customers	Case PUE-2012-00118
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202
Historic					
United States					
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2008-2013	No RAM	Docket 07-078-TF
CA	Bear Valley Electric Service	Electric	2009-2012	Stairstep	Decision 09-10-028
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	1979-1980	No RAM	Decision 89710
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1983-1984	Hybrid	Decision dated December 8, 1982
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CO	Public Service Company of Colorado	Gas	2008-2011	Customers	Decision C07-0568
CO	Public Service Company of Colorado	Electric	2012-2014	Stairstep	Decision C12-0494
CT	United Illuminating	Electric	2009-2013	Stairstep until 2011/No RAM for 2011 onwards	Docket 08-07-04
FL	Florida Power Corporation	Electric	1995-1997	Customers	Docket 930444
ID	Idaho Power	Electric	2007-2009	Customers	Case IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	Customers	Case IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	Customers	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	Customers	Case 07-0242
IN	Citizens Gas	Gas	2007-2011	Customers	Cause 42767
IN	Vectren Energy	Gas	2007-2011	Customers	Cause 43046
IN	Vectren Southern Indiana	Gas	2007-2011	Customers	Cause 43046
MA	Bay State Gas	Gas	2009-open	Customers	DPU 09-30
ME	Central Maine Power	Electric	1991-1993	Customers	Docket 90-085
MI	Consumers Energy	Electric	2009-2011	Customers	Case U-15645
MI	Consumers Energy	Gas	2010-2012	Customers	Case U-15986
MI	Detroit Edison	Electric	2010-2011	Customers	Case U-15768
MI	Michigan Consolidated Gas	Gas	2010-2012	Customers	Case U-15985
MI	Michigan Gas Utilities	Gas	2010-2013	Customers	Case U-15990
MI	Upper Peninsula Power	Electric	2010-2011	Customers	Case U-15988
MN	CenterPoint Energy	Gas	2010-2013	Customers	Docket GR-08-1075
MT	Montana Power Company	Electric	1994-1998	Customers	Docket 93.6.24

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
United States (cont'd)					
NC	Piedmont Natural Gas	Gas	2005-2008	Customers	Docket G-44 Sub 15
ND	Northern States Power - MN	Electric	2012	Not Applicable, plan only 1 year in duration	Case PU-11-55
NJ	New Jersey Natural Gas	Gas	2007-2010	Customers	Docket GR05121020
NJ	New Jersey Natural Gas	Gas	2010-2013	Customers	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	Customers	Docket GR05121019
NJ	South Jersey Gas	Gas	2010-2013	Customers	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	Customers	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009	No RAM	Case 08-E-0887
NY	Central Hudson G&E	Gas & Electric	2010-2013	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Central Hudson G&E	Gas & Electric	2013-open	Customers for Gas, No RAM for Electric	Case 12-M-0192
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion 92-8
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2010-2013	Revenue per Customer Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Corning Natural Gas	Gas	2012-2015	Revenue per Customer Stairstep	Case 11-G-0280
NY	Keyspan Energy Delivery - New York	Gas	2010-open	Revenue per Customer Stairstep	Case 06-G-1185
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion 92-8
NY	National Fuel Gas	Gas	2008-open	Customers	Case 07-G-0141
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Niagara Mohawk	Gas	2009-open	Customers	Case 08-G-0609
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Orange & Rockland Utilities	Gas	2012-2015	Customers	Case 08-G-1398
NY	Orange & Rockland Utilities	Gas	2009-2012	Revenue per Customer Stairstep	Case 08-G-1398
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion 93-19
OH	Duke Energy Ohio	Electric	2012-2014	Customers	Case 11-5905-EL-RDR
OH	Vectren Energy	Gas	2007-2009	Customers	Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2007-2012	Customers	Order 06-191
OR	Northwest Natural Gas	Gas	2002-2005	Customers	Order 02-634
OR	Northwest Natural Gas	Gas	2005-2009	Customers	Order 05-934
OR	Northwest Natural Gas	Gas	2009-2012	Customers	Order 07-426
OR	PacifiCorp	Electric	1998-2001	Indexing	Order 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order 95-0322
OR	Portland General Electric	Electric	2009-2010	Customers	Order 09-020
OR	Portland General Electric	Electric	2011-2013	Customers	Order 10-478
TN	Chattanooga Gas	Gas	2010-2013	Customers	Docket 09-0183
UT	Questar Gas	Gas	2006-2010	Customers	Docket 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	Customers	Case PUE-2008-00060
VA	Washington Gas Light	Gas	2010-2013	Customers	Case PUE-2009-00064
WA	Avista	Gas	2007-2009	Customers	Docket UG-060518
WA	Avista	Gas	2009-2012	Customers	Docket UG-060518
WA	Avista	Gas	2013-2014	Revenue per Customer Stairstep	Docket UG-120437
WA	Cascade Natural Gas	Gas	2005-2010	Customers	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	Customers	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	Customers	D-6690-UR-119
WI	Wisconsin Public Service	Gas & Electric	2013	Not Applicable, plan only 1 year in duration	Docket 6690-UR-121
WY	Questar Gas	Gas	2009-2012	Customers	Docket 30010-94-GR-08

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
Canada					
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Hydro	Electric	2009-2010	Hybrid	Order G-16-09
BC	BC Hydro	Electric	2011	Not Applicable, plan only 1 year in duration	Order G-180-10
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
ON	Enbridge Gas Distribution	Gas	2008-2012	Revenue per Customer Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Indexing	Docket EB-2007-0606

Fixed/variable pricing relaxes the revenue/usage link with low administrative cost since it requires neither decoupling true ups nor load impact calculations. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing so that rate cases tend to be less frequent even if the decline is largely driven by external forces. Base revenue grows more slowly than under conventional rate designs if average use is rising. The short term disincentive is removed to embrace various DSM initiatives. However, fixed/variable pricing reduces a utility's ability to use usage charges as a tool for promoting DSM. For example, it does not encourage customers with electric vehicles to charge these vehicles at night. Note also that the principle of rate design gradualism often discourages regulators from immediately adopting SFV pricing.

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed/variable pricing in retail ratemaking are listed below on Table 5 and Figure 6. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced, and the fact that the decline has been driven largely by external forces. Since our 2013 survey, fixed/variable pricing has been implemented for an electric utility in Oklahoma.

In addition to the precedents listed here, utilities in Wisconsin and several other states have in recent years made sizable steps in the direction of fixed/variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than are utilities in the United States. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 6: Fixed/Variable Pricing Precedents by State

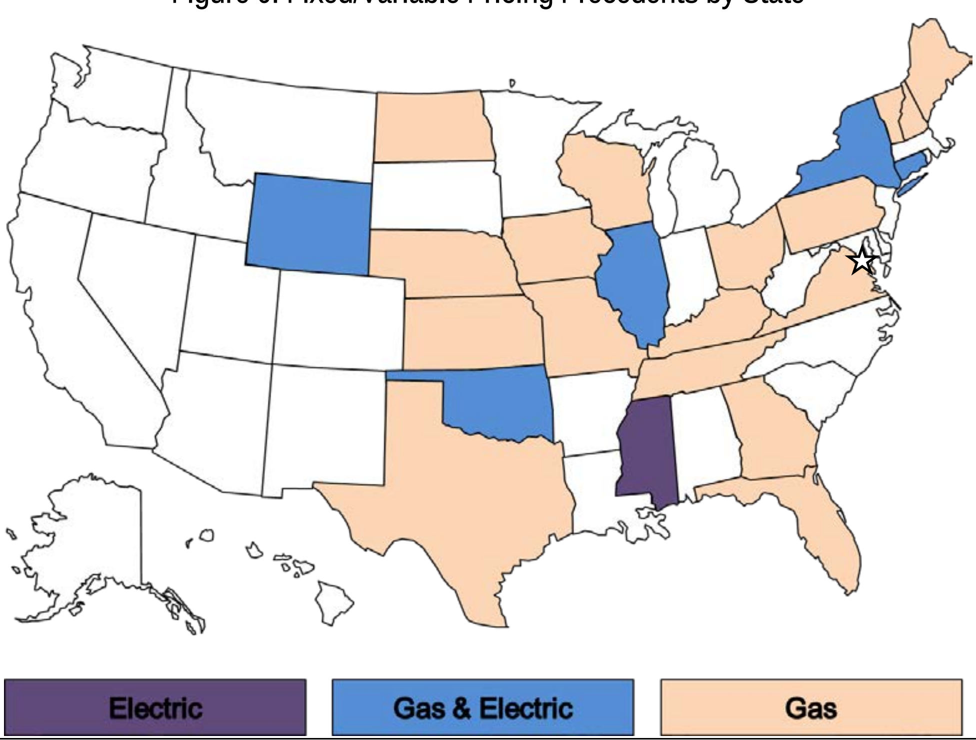


Table 5

Fixed Variable Residential Pricing Precedents[1]

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Connecticut Natural Gas	Gas	2014-open	Docket 13-06-08
CT	United Illuminating	Electric	Occurred over period of years	No specific case
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Liberty Utilities	Gas	2015-open	Docket 34734
IA	Black Hills Energy	Gas	2009-open	Docket RPU-08-3
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Ameren Illinois	Electric	Occurred over period of years	No specific case
IL	Commonwealth Edison	Electric	2011-2013	Case 10-0467
IL	Mt. Carmel Public Utilities	Gas	2013-open	Case 13-0079
IL	North Shore Gas	Gas	2008-open	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case 07-0242
KS	Atmos Energy	Gas	2010-open	Docket 10-ATMG-495-RTS
KS	Black Hills Energy (formerly Aquila)	Gas	2007-open	Docket 07-AQLG-431-RTS
KS	Kansas Gas Service	Gas	2012-open	Docket 12-KGSG-835-RTS
KY	Atmos Energy	Gas	2014-open	Case 2013-00148
KY	Columbia Gas	Gas	2013-open	Case 2013-00167
KY	Delta Natural Gas	Gas	2007-open	Case 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case 2009-00202
ME	Maine Natural Gas	Gas	Occurred over period of years	Docket 2009-00067
ME	Northern Utilities	Gas	2014-open	Docket 2013-00133
MO	AmerenUE	Gas	2007-open	Case GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
NE	SourceGas Distribution	Gas	2012-open	Docket NG-0067
NH	Liberty Utilities (EnergyNorth Natural Gas)	Gas	Occurred over period of years	No specific case
NH	Northern Utilities	Gas	2014-open	DG 13-086
NY	Central Hudson Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
NY	Consolidated Edison	Electric & Gas	Occurred over period of years	No specific case
NY	Corning Gas	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - Long Island	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - New York	Gas	Occurred over period of years	No specific case
NY	National Fuel Gas	Gas	Occurred over period of years	No specific case

Table 5 (cont'd)

Jurisdiction	Company Name	Services	Years in Place	Case Reference
NY	New York State Electric & Gas	Electric	Occurred over period of years	No specific case
NY	Niagara Mohawk	Electric & Gas	Occurred over period of years	No specific case
NY	Orange & Rockland	Electric & Gas	Occurred over period of years	No specific case
NY	Rochester Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Arkansas Oklahoma Gas	Gas	2013-open	Cause PUD 201200236
OK	Centerpoint Energy	Gas	2010-open	Cause PUD 201000030
OK	Oklahoma Natural Gas	Gas	2004-open	Causes PUD 200400610, PUD 201000048, PUD 200900110
OK	Public Service Company of Oklahoma	Electric	2015-open	Cause PUD 201300217
PA	Columbia Gas	Gas	2013-open	Docket R-2012-2321748
TN	Atmos Energy	Gas	2012-open	Docket 12-00064
TN	Piedmont Natural Gas	Gas	2012-open	Docket 11-00144
TX	Atmos Energy - Mid-Tex Division	Gas	Occurred over period of years	No specific case
TX	Atmos Energy - West Texas Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Houston Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Beaumont/East Texas Division	Gas	Occurred over period of years	No specific case
VA	Columbia Gas of Virginia	Gas	Occurred over period of years	No specific case
VT	Vermont Gas Systems	Gas	Occurred over period of years	No specific case
WI	Madison Gas & Electric	Gas	2015-open	Docket 3270-UR-120
WI	Wisconsin Public Service	Gas	2015-open	Docket 6690-UR-123
WY	SourceGas Distribution	Gas	2011-open	Docket 30022-148-GR-10
WY	PacifiCorp (d/b/a Rocky Mountain Power)	Electric	2009-open	Docket 20000-333-ER-08

[1] Fixed variable pricing precedents include power and gas distributors that have a customer charge equal to or in excess of $15 (or $20 for vertically integrated electric utilities).

IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants (e.g., the residential delivery volume) are jointly considered in ratesetting. A historical test year ends before the rate case is filed. A forward (a/k/a "fully forecasted") test year ("FTY") begins after the rate case is filed. An FTY typically begins about the time the rate case is expected to end and new rates take effect. Two-year forecasts may be required in this event which span both the year of the rate case and the rate effective year.[4] In between forward and historical test years is the option of a "partially forecasted" test year in which some months of historical data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historical test years tend to be uncompensatory when cost is growing faster than billing determinants. Annual rate cases with historical test years can alleviate but not eliminate underearning under these conditions. The effect on credit metrics can be material. [5] Where historical test years are used, there are thus added advantages to implementing other Altreg innovations discussed in this survey.

Forward test years can fully compensate utilities when cost growth exceeds growth in billing determinants. If this imbalance is chronic, however, FTYs do not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, such as cost trackers or multiyear rate plans.

Many approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalize data for an historical reference period, adjusted for known and measurable changes, and then use indexing and other statistical methods to extend projections. A mixture of forecasting methods is common. For example, index-based forecasting may be used only for O&M expenses.

FTYs were adopted in many jurisdictions during the 1970s and 1980s, when rapid inflation and major plant additions coincided with oil shock-induced slowdowns in the growth of average use. Several additional states have recently moved in the direction of FTYs. Some of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized below in Figure 7 and Table 6. In many jurisdictions the use of partially or fully-forecasted test years is not standardized. For example, in some jurisdictions, including Illinois and North Dakota, utilities are allowed to select their type of rate case test year. Test year selection may also be made part of the rate case (e.g., Utah). A few jurisdictions allow forward test years to be used in rate cases or formula rate plans, but not both (e.g., Illinois and Arkansas).

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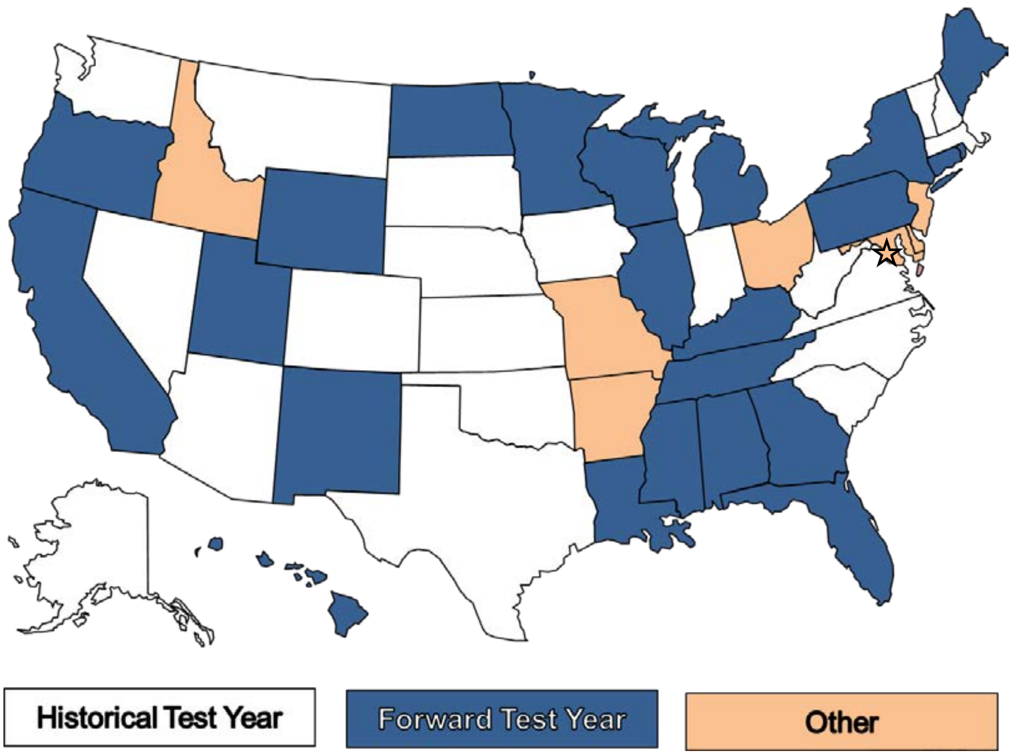
[4] A forward test year can in principle be the rate case year, and thereby not require two-year forecasts. Proposed rates can be established on an interim basis shortly after the filing.

[5] For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, Edison Electric Institute, 2010.

Because of these complications, we have separated Table 6 into separate sections, specifying where FTYs are commonly used or occasionally used. Figure 7 shows jurisdictions where FTYs are commonly or occasionally used. Jurisdictions where partially-forecasted test years are commonly or occasionally used are in the category titled Other, with the remaining jurisdictions counted as historical test years.

The ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total. Since our 2013 survey, electric utilities in Pennsylvania have successfully used FTYs and utilities in Arkansas and Indiana have received legislative authorization for their use.[6][7] Forward test years are the norm in Canadian regulation.

Figure 7: Test Year Policy by State



[6] In addition, another electric utility in Mississippi was recently permitted to use a forward-looking formula rate plan.
[7] FTYs in Arkansas can only be used in formula rate plans.

Table 6

Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted Test Years Commonly Used (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use historical test years
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Fully-Forecasted Test Years Occasionally Used (9)	
Illinois	Utilities use various test years including forward test years ("FTYs")
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Mississippi	Both electric utilities operate under forward-looking formula rate plans. Gas formula rate plans rely on historical test years ("HTYs").
New Mexico	A recently passed law allows for use of FTYs, and at least one rate increase based on FTY evidence has been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have traditionally been the norm. However, a law allowing fully-forecasted test years passed in 2012 and several electric utility rate increases based on FTY evidence have been approved.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Partially-Forecasted Test Years Commonly or Occasionally Used (8)	
Arkansas	Utilities have typically used partially forecasted test years in rate cases. However, a recent bill authorized the use of formula rates with either historical or forecasted test periods.
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Idaho	
Maryland	Utilities use various test years excluding FTYs
Missouri	Utilities have the option to file partially-forecasted test years
New Jersey	
Ohio	
Historical Test Years Commonly Used (20)	
Alaska	
Arizona	
Colorado	Utilities have filed FTY evidence. However, no FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has been approved for an energy utility to date
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to reduce regulatory cost, while increasing the utility incentive for efficient operation. Rate cases are held infrequently, most often at three to five year intervals. Between rate cases, rate escalations are based on a combination of automatic attrition relief mechanisms ("ARMs") and cost trackers. The 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.

The "externalization" of ratemaking that ARMs and rate case moratoria achieve gives utilities more opportunity to profit from improved performance. Benefits of better performance can be shared between the utility and its customers. Performance incentives are strengthened despite streamlined regulation. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs can cap growth in rates (e.g., customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster customer use of the grid. Revenue caps are usually combined with revenue decoupling mechanisms, and are often favored where utilities must cope with declining average use and/or policymakers strongly encourage DSM.

Several approaches to ARM design are well-established. These include multiyear cost forecasts, indexing, and hybrids. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in other cost drivers like the number of customers served. A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue.

The indexing approach to ARM design has been more common for UDCs because their cost growth is relatively gradual and predictable. Hybrid and forecasted ARMs have historically been more common for vertically integrated electric utilities because occasional major plant additions have given their cost trajectories more of a "stairstep" pattern. However, this pattern is becoming less common in an era when demand growth is slower and fewer large power plants are under construction. Some VIEUs operating under MRPs have separate ARMs for generation and distribution.

Cost trackers are often used in MRPs to address changes in business conditions that are difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. MRPs with "tracker/freeze" provisions for vertically integrated utilities often accord tracker treatment to costs of new or refurbished generating plants.[8] Trackers also address *force majeure* events like severe storms and changes in tax rates that affect costs.

Many MRPs feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some MRPs feature "off-ramps" that permit plan suspension when earnings are unusually high or low.

[8] A good example is the Generation Base Rate Adjustment in the current MRP of Florida Power & Light.

Plans often feature performance incentive mechanisms that are linked to the utility's service quality. With stronger cost containment incentives, there is a greater need for a link between revenue and service quality. Many MRPs combine revenue decoupling, the tracking of DSM expenses, and performance incentives for DSM. The stronger incentive to contain cost that MRPs provide then becomes a "fourth leg" for the DSM stool.

MRPs have long been used to regulate utilities where market-responsive rates and services are a priority. Infrequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings and lessen concerns about cross-subsidization. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

For example, in the early 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options. The commission, under the chairmanship of Thomas Welch (a former telecom industry lawyer) approved a succession of price cap plans for Central Maine Power which facilitated marketing flexibility. As a result, the company had more freedom to enter into special contracts. The stronger incentives the company had to offer the right discounts to customers at risk of bypass was acknowledged by the commission when costs were allocated in later rate cases.

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated in Table 7 and Figures 8a and 8b.[9] In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have been adopted by well-known VIEUs in Florida, North Dakota, and Virginia since our 2012 survey. A number of states have, additionally, experimented with "mini-MRPs" with terms of only two years. The forecast and tracker/freeze approaches to ARM design are most common currently in the US. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

[9] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from Table 7 and Figures 8a and 8b.

Figure 8a: Recent US Multiyear Rate Plan Precedents by State

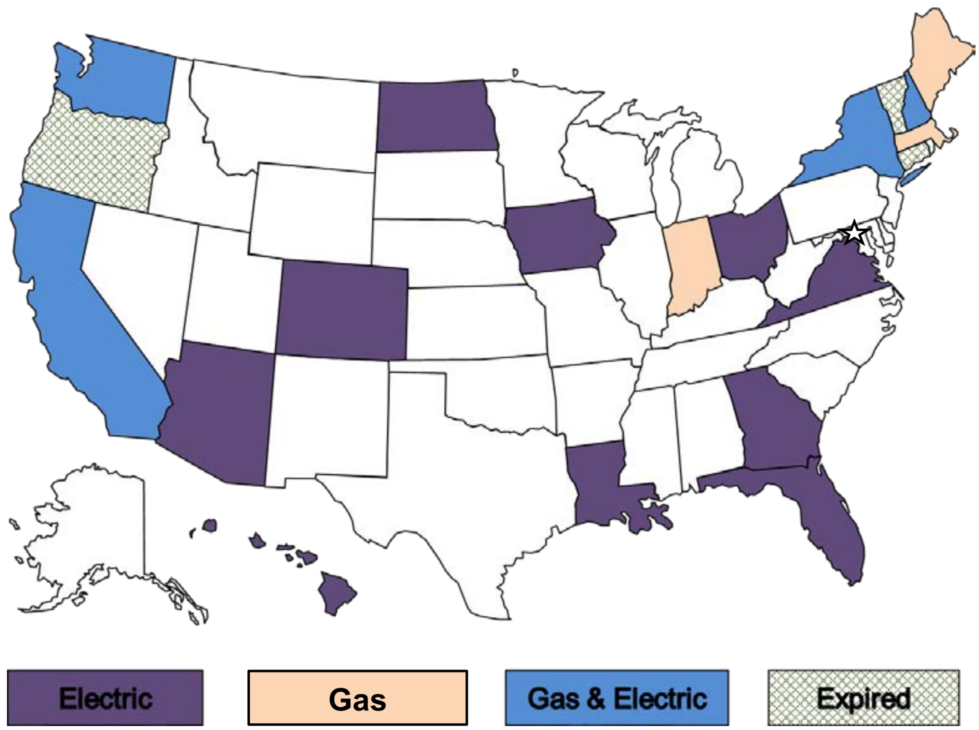


Figure 8b: Recent Canadian Multiyear Rate Plan Precedents by Province

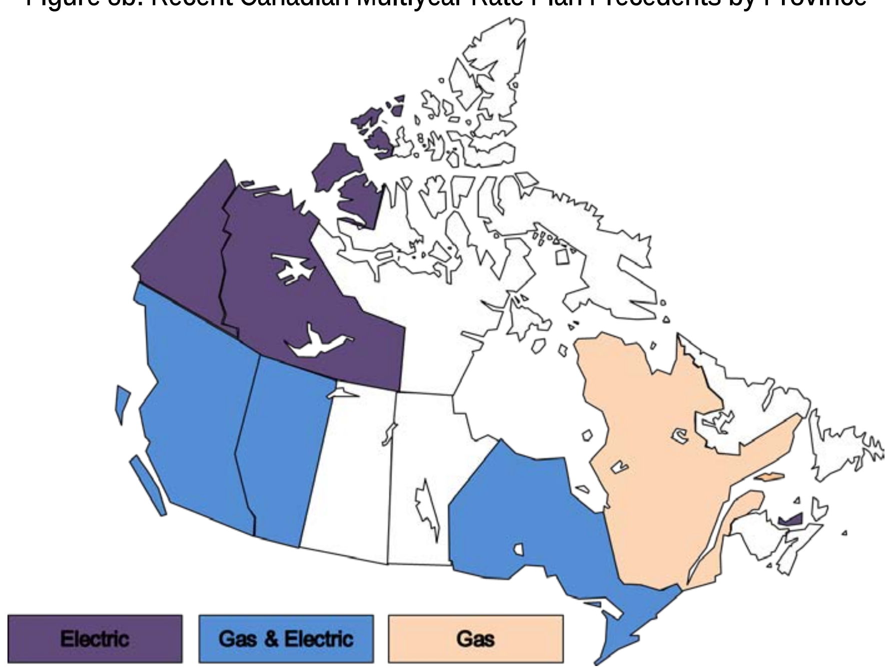


Table 7

Multiyear Rate Plan Precedents [1]

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current						
United States						
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate Freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capital and other cost trackers, LRAM	None	Decision 73183; May 2012
CA	Bear Valley Electric Service	2013-2016	Power distribution	Revenue Cap Stairstep	None	Decision 14-11-002; November 2014
CA	California Pacific Electric	2013-2015	Power distribution	Revenue Cap Index	None	Decision 12-11-030; November 2012
CA	Pacific Gas & Electric	2014-2016	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 14-08-032; August 2014
CA	PacifiCorp	2011-2013, extended through 2016	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings	None	Decision 10-09-010; September 2010
CA	San Diego Gas & Electric	2012-2015	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southern California Gas	2012-2015	Gas	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southwest Gas	2014-2018	Gas	Revenue Cap Stairstep	None	Decision 14-06-028; June 2014
CO	Public Service of Colorado	2015-2017	Bundled power service	Rate Freeze with multiple capital cost trackers	Sharing of overearnings only up to earnings cap	Decision C15-0292; March 2014
FL	Florida Power & Light	2013-2016	Bundled power service	Rate Freeze with multiple capital and other cost trackers	None	Docket 120015-EI; December 2012
FL	Gulf Power	2014-June 2017	Bundled power service	Price Cap Stairstep through 2015, Rate Freeze beyond	None	Docket 130140-EI; December 2013
FL	Duke Energy Florida (formerly Progress Energy Florida)	2012-2016, extended through 2018	Bundled power service	Rate Freeze with one step plus capital and other cost trackers	None	Dockets 120022-EI and 130208-EI; 2012 and November 2013
FL	Tampa Electric	2013-2017	Bundled power service	Revenue Cap Stairstep	None	Docket 130040-EI
GA	Georgia Power	2014-2016	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with deadband	Docket 36989; December 2013
HI	Hawaiian Electric Company	2012-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2008-0083
HI	Hawaiian Electric Light Company	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0164
HI	Maui Electric	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0163
IA	MidAmerican Energy	2014-2017	Bundled power service	Revenue Cap Stairstep for 2014-2016, Rate Freeze for 2017	Sharing of overearnings only with deadband up to earnings cap	RPU-2013-0004
IN	Northern Indiana Public Service Company	2015-2020	Gas	Rate Freeze with capital and other cost trackers, possible reopening in 2017	Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less	Cause 43894 and 44403 TDSIC 1 (August 2013 and January 2015)
LA	Cleco Power	2014-2017	Bundled power service	Rate Freeze with capital and other cost trackers	Sharing of overearnings only with deadband up to earnings cap	Docket U-32779; June 2014
MA	Bay State Gas	2015-2018	Gas	Revenue Cap Stairstep for 2015, 2016, Revenue Freeze through October 2018	None	DPU 15-150; October 2015
ME	Summit Natural Gas of Maine	2013-2022	Gas	Price Cap Indexing: 75% of change in GDPPI	None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband	Docket 2012-258; January 2013
NH	Northern Utilities	May 2014 - April 2017	Gas	Revenue Cap Stairstep for 2014-2015, Rate Freeze in 2016	Sharing of overearnings only with deadband up to earning cap	DG 13-086; April 2014
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	Sharing of overearnings only with deadband	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	Sharing of overearnings only with deadband	DE 10-055

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
United States (cont'd)						
NY	Central Hudson Gas & Electric	2015-2018	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	2014-2016	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 13-G-0031
NY	Corning Natural Gas	2012-2015	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-G-0280
NY	Orange & Rockland Utilities	November 2015-October 2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple sharing bands	Case 14-G-0494
ND	Northern States Power - Minnesota	2013-2016	Bundled power service	Revenue Cap Stairstep for 2013-2015, Rate Freeze in 2016	Sharing of overearnings only without deadband, earnings adjusted for effects of weather	Case PU-12-813
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Cases 11-388-EL-SSO, 12-1230-EL-SSO
US	All	2011-2016	Oil pipelines	Price Cap Index: PPI-Finished Goods + 2.65%	None	Docket RM10-25-000; December 2010
VA	Appalachian Power	2014-2017	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
VA	Virginia Electric Power	2015-2019	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
WA	Puget Sound Energy	2013-2016	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, equal sharing between company and customers	Dockets UE-121697 and UG-121705
Canada						
Alberta	Altagas Utilities and ATCO Gas	2013-2017	Gas	Revenue per Customer Indexing: Input price index - 1.16%, + capital cost trackers	None	Decision 2012-237
Alberta	ATCO Electric, EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, + capital cost trackers	None	Decision 2012-237
British Columbia	FortisBC	2014-2018	Bundled power service	Revenue Cap Index: I-Factor - 1.03%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698719, Decision; September 2014
British Columbia	FortisBC Energy	2014-2018	Gas	Revenue Cap Index: I-Factor - 1.1%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698715, Decision; September 2014
Ontario	All unless company opts out	2014-2018	Power distribution	Price Cap Index: Input price index - (0%+stretch); stretch factor reassigned annually, + capital cost tracker option available	None	EB-2010-0379 Report of the Board; November 2013
Ontario	Horizon Utilities	2015-2019	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2014-0002; December 2014
Ontario	Hydro One Networks	2015-2017	Power distribution	Revenue Cap Stairstep	None	EB-2014-0247; March 2015
Ontario	Enbridge Gas Distribution	2014-2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2012-0459, Decision with Reasons; July 2014
Ontario	Union Gas Limited	2014-2018	Gas	Revenue Cap Index: 40% of growth in GDP-IPI	Sharing of overearnings only with deadband, multiple sharing ranges	EB 2013-0202 Decision; October 2013
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Price Cap Stairstep: Bill defines rates for each year.	Earnings cap set at allowed ROE, no floor	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act
Quebec	Gazifere	2011-2015	Gas distribution	Price Cap Index	Sharing of overearnings only without deadband and multiple sharing bands up to earnings cap	D-2010-112; August 2010
Yukon Territory	Yukon Electrical Company, Limited	2013-2015	Bundled power service	Revenue Cap Stairstep	None	Board Order 2014-06; April 2014

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Great Britain						
Great Britain	All	2013-2021	Gas and power transmission	British-Style Hybrid	Not reviewed	RIIO-T1 Final Proposals, April and December 2012
Great Britain	All	2013-2021	Gas distribution	British-Style Hybrid	Not reviewed	RIIO-GD1 Final Proposals, December 2013
Great Britain	All	2015-2023	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	RIIO-ED1 Final Proposals, December 2014
Australia/New Zealand						
Australia	ActewAGL	2015-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	Final Decision ActewAGL distribution determination 2015-16 to 2018-19; April 2015
Australia	Ausgrid	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ausgrid distribution determination 2015-16 to 2018-19; April 2015
Australia	Directlink	2015-2020	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision Directlink transmission determination 2015-16 to 2019-20; April 2015
Australia	Endeavour Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Energex	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Energex determination 2015-16 to 2019-20
Australia	Ergon Energy	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ergon Energy determination 2015-16 to 2019-20
Australia	Essential Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Essential Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Jemena Gas Networks	2015-2020	Gas distribution	Australian-Style Hybrid	Not reviewed	Final Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015−20; June 2015
Australia	SA Power Networks	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision SA Power Networks determination 2015-16 to 2019-20
Australia	TasNetworks	2015-2019	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TasNetworks transmission determination 2015-16 to 2018-19; April 2015
Australia	TransGrid	2015-2018	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TransGrid transmission determination 2015-16 to 2017-18; July 2015
Australia	Power & Water	2014-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	2014 Networks Price Determination Final Determination Part-A Statement of Reasons; April 2014
Australia	All Queensland Distributors	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for Qld Gas Network, Final Decision; June 2011
Australia	Energex and Ergon Energy	2010-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Queensland Distribution Determination 2011-11 to 2014-15 (Final Decision)
Australia	Envestra	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for the SA Gas Network, Final Decision; June 2011
Australia	All Victorian Distributors	2013-2017	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Final Decision; March 2013

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Australia/New Zealand (cont'd)						
Australia	CitiPower	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	CitiPower Pty Distribution Determination 2011-2015; September 2012
Australia	Powercor	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Powercor Australia Ltd Distribution Determination 2011-2015; October 2012
Australia	Jemena Electricity Networks	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Jemena Electricity Networks (Victoria) Ltd Distribution Determination 2011-2015; September 2012
Australia	SP AusNet	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	SPI Electricity Pty Ltd Distribution Determination 2011-2015; August 2013
Australia	United Energy Distribution	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	United Energy Distribution Distribution Determination 2011-2015; September 2012
New Zealand	All but Orion Electric	2015-2020	Power distribution	Revenue Cap Index: CPI-0% for most companies	None	Project no. 14.07/14118; November 2014
New Zealand	All	2013-2017	Gas distribution	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
New Zealand	All	2013-2017	Gas transmission	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
Historic						
United States						
CA	Bear Valley Electric Service	2009-2012	Power distribution	Revenue Cap Stairstep	None	Decision 09-10-028; October 2009
CA	Pacific Gas & Electric	2011-2013	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 11-05-018; May 2011
CA	Pacific Gas & Electric	2007-2010	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 07-03-044; March 2007
CA	Pacific Gas & Electric	2004-2006	Gas & bundled power service	Revenue Cap Index	None	Decision 04-05-055; May 2004
CA	Pacific Gas & Electric	1993-1995	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 92-12-057; December 1992
CA	Pacific Gas & Electric	1990-1992	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 89-12-057; December 1989
CA	Pacific Gas & Electric	1987-1989	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 86-12-092; December 1986
CA	Pacific Gas & Electric	1984-1986	Gas & bundled power service	Revenue Cap Hybrid	None	Decisions 83-12-068; December 1983 and 85-12-076; December 1985
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	None	Decisions 06-12-011; December 2006 and 09-04-017; April 2009
CA	PacifiCorp	1994-1996	Bundled power service	Price Cap Index	None	Decision 93-12-106; December 1993
CA	PacifiCorp	1984-1987	Bundled power service	Revenue Cap Hybrid	None	Decisions 84-07-150; July 1984 and 85-12-076; December 1985
CA	San Diego Gas & Electric	2008-2011	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	San Diego Gas & Electric	2005-2007	Gas & bundled power service	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	San Diego Gas and Electric	1999-2002	Gas & power distribution	Price Cap Index	Sharing of overearnings only above deadband with multiple sharing bands	Decision 99-05-030; May 1999

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
CA	San Diego Gas & Electric	1994-1999	Gas & bundled power service	Revenue Cap Hybrid	Sharing of overearnings only with deadband and multiple sharing bands up to an earnings cap	Decision 94-08-023; August 1984
CA	San Diego Gas & Electric	1989-1993	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 88-12-085; December 1988
CA	San Diego Gas & Electric	1986-1988	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 85-12-108; December 1985
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	None	Decision 09-10-041; October 2009
CA	Sierra Pacific Power	1990-1992	Bundled power service	Revenue Cap Hybrid	None	Decision 90-07-060; July 1990
CA	Southern California Edison	2012-2014	Bundled power service	Revenue Cap Hybrid	None	Decision 12-11-051; November 2012
CA	Southern California Edison	2009-2011	Bundled power service	Revenue Cap Stairstep	None	Decision 09-03-025; March 2009
CA	Southern California Edison	2006-2008	Bundled power service	Revenue Cap Hybrid	None	Decision 06-05-016; May 2006
CA	Southern California Edison	2004-2006	Bundled power service	Revenue Cap Hybrid	None	Decision 04-07-022; July 2004
CA	Southern California Edison	1997-2001	Power distribution	Price Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 96-09-092; September 1996
CA	Southern California Edison	1986-1991	Bundled power service	Revenue Cap Hybrid	None	Decision 85-12-076; December 1985
CA	Southern California Gas	2008-2011	Gas	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	Southern California Gas	2005-2007	Gas	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	Southern California Gas	1998-2003	Gas	Revenue Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 97-07-054; July 1997
CA	Southern California Gas	1990-1993	Gas	Revenue Cap Hybrid	None	Decision 90-01-016; January 1990
CA	Southern California Gas	1985-1989	Gas	Revenue Cap Hybrid	None	1984, 85-12-076; December 1985, and 87-05-027; May 1987
CA	Southwest Gas	2009-2013	Gas	Revenue Cap Stairstep	None	Decision 08-11-048; November 2008
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, multiple sharing bands up to earnings cap	Decision C12-0494
CT	Connecticut Light & Power	2004-2007	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 03-07-02
CT	United Illuminating	2006-2008	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capital and other cost trackers	None	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate Freeze with 1 step to reflect generation brought in-service and multiple capital and other cost trackers	None	Docket 050078-EI
GA	Georgia Power	2011-2013	Bundled power service	Revenue Cap Stairstep: Rate increases permitted for DSM and major generation plant additions	Sharing of overearnings only with deadband	Docket 31958
IA	MidAmerican Energy	2001-2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capital and other cost trackers	Sharing of overearnings only in multiple sharing bands, deadband not applicable due to no allowed ROE	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco Power	2009-2014	Bundled power service	Rate Freeze with capital cost tracker	Sharing of overearnings only with deadband up to earnings cap	Order U-30689
MA	Bay State Gas	2006-2015, terminated in 2009	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 05-27
MA	Berkshire Gas	February 2002-January 2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	None	Docket D.T.E. 01-56

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket D.P.U. 96-50-C (Phase I); May 1997
MA	Boston Gas (II)	2004-2013, Terminated in 2010	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Even sharing of earnings above/below deadband	Docket D.T.E. 04-79
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Deadband with 50-50 sharing of over and underearnings	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas distribution	Price Cap Index	Even sharing of overearnings only. No allowed ROE established for company and no determination of a deadband.	Docket 970795; June 1998
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	50/50 sharing around deadband	Docket 97-116; March 1998
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Even sharing of earnings above/below deadband	Docket 92-345 Phase II; January 1995
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	50-50 sharing below deadband	Docket 99-666; November 2000
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate capital cost tracker for AMI	50-50 sharing above 11% ROE	Docket 2007-215
ME	Maine Natural Gas	2010-2012	Gas	Revenue Cap Stairstep with steps conditioned on company earnings	None	Docket 2009-67
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	Case 90-G-0981, Opinion 91-21; October 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband and multiple sharing bands	Case 93-G-0941, Opinion 94-22; October 1994
NY	Central Hudson Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Case 09-E-0588
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Gas & power distribution	Price Cap Stairstep	Sharing of overearnings only with deadband, multiple sharing bands up to earnings cap	Case 05-E-0934 & Case 05-G-0935; July 2006
NY	Consolidated Edison	2010-2013	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-G-0795
NY	Consolidated Edison	2007-2010	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband, sharing threshold adjustable depending on work with DSM program administrator for first year only	Case 06-G-1332
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 93-G-0996, Opinion 94-2; October 1994
NY	Consolidated Edison	2010-2013	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 09-E-0428
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Price Cap Stairstep	Sharing of overearnings only with multiple bands. No allowed ROE approved.	Case 04-E-0572; March 2005
NY	Consolidated Edison	1992-1995	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings with varying allowed ROE and no deadband	Opinion 92-8
NY	Keyspan Energy Delivery - Long Island	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1185
NY	Keyspan Energy Delivery - New York	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1186
NY	Long Island Lighting Company	December 1, 1993-November 30, 1996	Gas	Revenue Cap Stairstep	Even sharing of overearnings only with deadband	Case 93-G-002, Opinion 93-23; December 1993
NY	Long Island Lighting Company	1992-1994	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only without deadband	Opinion 92-8

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
NY	New York State Electric & Gas	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0715
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with annually varying deadbands	Case 94-M-0349, Opinion 95-27; September 1995
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas & bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 92-G-1086, Opinion 93-22; November 1993
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband up to earnings cap	Case 29327, Opinion 89-37; June 1991
NY	Orange & Rockland Utilities	2009-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 08-G-1398
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Price Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 05-G-1494; October 2006
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Price Cap Stairstep	Even sharing of overearnings only without deadband	Case 02-G-1553; October 2003
NY	Orange & Rockland Utilities	2012-2015	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-E-0408
NY	Orange & Rockland Utilities	2008-2011	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 07-E-0949
NY	Orange & Rockland Utilities	1991-1993	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings above deadband	Case 89-E-175
NY	Rochester Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0717
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas & bundled power service	Revenue Cap Stairstep	Earnings cap only	Case 92-G-0741, Opinion No. 93-19; August 1993
OH	AEP-Ohio	2012-2015	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Case No. 11-346-EL-SSO; August 2012
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Price Cap Stairstep	Company subject to Significantly Excessive Earnings Test conducted annually	Case 08-920-EL-SSO
OR	PacifiCorp	1998-2001	Power distribution	Revenue Cap Index	Sharing of over/underearning outside deadband in multiple sharing bands	Order No. 98-191
US	All	2006-2011	Oil pipelines	Price Cap Index: PPI-Finished Goods + 1.3%	None	RM05-22-000
US	All	2001-2006	Oil pipelines	Price Cap Index: PPI-Finished Goods + 0%	None	RM00-11-000
US	All	1995-2001	Oil pipelines	Price Cap Index: PPI-Finished Goods - 1%	None	RM93-11-000
VT	Green Mountain Power	2007-2010	Bundled power service	Revenue Cap Stairstep	Earnings cap for overearnings above deadband; Multiple sharing bands for earnings apply if actual ROE below deadband (earnings floor of the deadband also applies)	Docket No. 7176
WA	Puget Sound Energy	1997-2001	Bundled power service	Price Cap Stairstep	None	Docket UE-960195
Australia/New Zealand						
Australia	Jemena Gas Networks	2010-2015	Gas distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement Proposal for NSW Gas Networks, Final Decision; June 2010
Australia	All New South Wales distributors	2009-2014	Power distribution	Australia-Style Hybrid	Not reviewed	New South Wales Distribution Determination 2009-10 to 2013-14 Final Decision
Australia	ElectraNet	2008-2013	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; April 2008
Australia	ElectraNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1094
Australia	Powerlink	2007-2012	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; June 2007

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
Australia	Powerlink	2002-2007	Power transmission	Australia-Style Hybrid	Not reviewed	File No: 2000/659
Australia	Snowy Mountains	1999-2004 (terminated in 2002 due to merger with Transgrid)	Electric transmission	Australia-Style Hybrid	Not reviewed	File No: C1999/62
Australia	SPI PowerNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1093
Australia	Transend	2009-2014	Power transmission	Australia-Style Hybrid	Not reviewed	Transend Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transend	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1100
Australia	Transgrid	2009-2014	Electric transmission	Australia-Style Hybrid	Not reviewed	Transgrid Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transgrid	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No. M2003/287
Australia	Transgrid	1999-2004	Power transmission	Australia-Style Hybrid	Not reviewed	File No: CG98/118
Australia- New South Wales	Country Energy Gas	2006-2010	Gas distribution	Australia-Style Hybrid	Not reviewed	Revised Access Arrangement for Country Energy Gas Network, Final Decision; November 2005
Australia- New South Wales	AGL Gas Networks	1999-2004	Gas transmission & distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement for AGL Gas Networks Limited, Final Decision; July 2000
Australia - New South Wales	All	2004-2009	Power distribution	Australia-Style Hybrid	Not reviewed	File No: S2004/138
Australia - New South Wales	All	1999-2004	Power distribution	Australia-Style Hybrid	Not reviewed	NEC Determination 99-1
Australia - Northern Territory	Power & Water	2000-2003	Power transmission & distribution	Australia-Style Hybrid	Not reviewed	Revenue Determinations document; June 2000
Australia - Northern Territory	Power & Water	2009-2014	Power transmission & distribution	Price Cap Index: CPI + 0.85%	Not reviewed	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Australia - Northern Territory	Power & Water	2004-2009	Power transmission & distribution	Price Cap Index: CPI - 2%	Not reviewed	Final Determination Networks Pricing: 2004 Regulatory Reset; February 2004
Australia -Victoria	All	2008-2012	Gas distribution	Australia-Style Hybrid	Not reviewed	Gas Access Aragement Review 2008-2012, Final Decision; March 2008
Australia -Victoria	All	2003-2007	Gas distribution	Australia-Style Hybrid	Not reviewed	Review of Gas Access Arrangements, Final Decision; October 2002
Australia -Victoria	All	2006-2010	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Review 2006-2010 (Final Decision Volume 1)
Australia -Victoria	All	2001-2005	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Determination 2001-2005 (Final Decision Volume 1)
New Zealand	All	2010-2015	Power distribution	Revenue Cap Index: CPI - 0%	None	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
New Zealand	All	2004-2009	Power distribution	Revenue Cap Index: CPI - 0.86% (Average across firms)	None	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Canada						
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	50-50 for excess earnings above deadband	Decision 2009-035
Alberta	Northwestern Utilities	1999-2002, reopened for 2001-2002	Gas distribution	Revenue Cap Stairstep; at reopener replaced with rate freeze	Sharing of earnings above/below deadband with multiple bands for overearnings; at reopener simplified to 50/50 sharing of overearnings with deadband	Decision U98060; March 1998 and Decision 2000-85; December 2000
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	None	City of Edmonton Distribution Tariff Bylaw 12367; August 2000
Northwest Territory	Northland Utilities	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 17-2011; November 2011
Northwest Territory	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 13-2011; August 2011
Ontario	All Ontario Distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	None	EB-2007-0673; July 2008, September 2008, and January 2009
Ontario	All Ontario Distributors	2006-2009	Power distribution	Price Cap Index	None	EB-2006-0089; December 2006
Ontario	All Ontario Distributors	2000-2003	Power distribution	Price Cap Index	50-50 sharing of excess earnings without deadband	RP-1999-0034; January 2000
Ontario	Enbridge Gas Distribution	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI * 53%	50-50 sharing of excess earnings above deadband	EB-2007-0615; February 2008
Ontario	Union Gas	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI -1.82%	Sharing of overearnings only with deadband and multiple sharing bands	EB-2007-0606; January 2008
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	50-50 sharing around deadband	RP-1999-0017; July 2001
Great Britain						
Great Britain	All	2008-2013	Gas distribution	British-Style Hybrid	Not reviewed	Review- Final Proposals; Published December 2007
Great Britain	All	2002-2007, extended to 2008	Gas distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2007-2012	Gas transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Great Britain	All	2002-2007	Gas transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	1998-2002	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1994-1997	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1992-1994	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
England & Wales	All	1995-2000	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2010-2015	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	Ofgem Distribution Price Control Review 5
Great Britain	All	2005-2010	Power distribution	British-Style Hybrid	Not reviewed	Ofgem Distribution Price Control Review 4

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Great Britain (cont'd)						
Great Britain	All	2000-2005	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	2001-2006, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	OECD Reviews of Regulatory Reform
England & Wales	National Grid	1997-2001	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	1993-1997	Power transmission	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.452
Great Britain	All	2007-2012	Power transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Scotland	All	2000-2005, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Scotland	All	1995-2000	Power transmission	British-Style Hybrid	Not reviewed	1995 Report by Monopolies and Mergers Commission

[1] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from this table.

VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service. 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. Regulatory cost is contained by limiting review of costs and revenues.

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. Both approaches can keep the utility whole for the time value of money.

Earning true up mechanisms often include a deadband in which variances don't trigger a rate adjustment. Once the variance exceeds the deadband, however, earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between the earnings true up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans.

Formula rates do not always address major plant additions. In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is often recovered through a separate tracker.

Mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its O&M expenses may be limited by a formula tied to an inflation index. FRPs in several states that include Illinois and Mississippi contain a number of targeted performance incentive mechanisms.

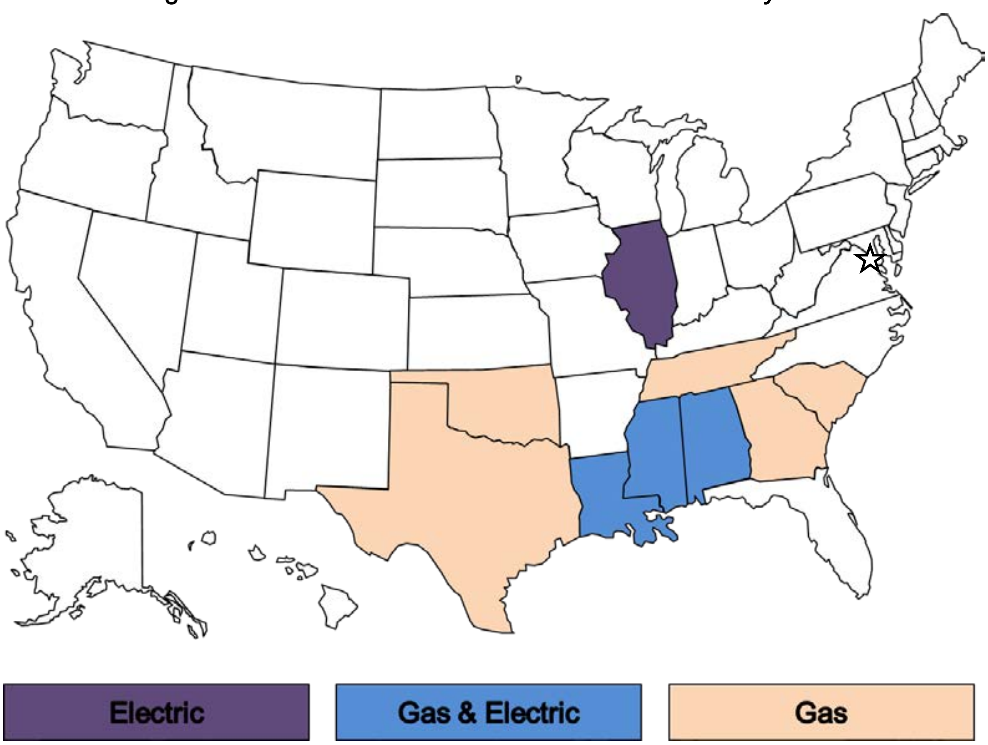
Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of energy utilities for decades. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 8 and Figure 9.[10] It can be seen that FRPs for retail utility services are most common in the Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization"

[10] Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition. These usually take the form of ESMs that may or may not protect the utility from underearning.

plans for Alabama Power and Alabama Gas in the early 1980s.[11] Formula rates are now used to regulate electric utilities in Illinois, some gas and electric utilities in Louisiana and Mississippi, and some gas utilities in Georgia, Oklahoma, South Carolina, Tennessee, and Texas. Most of the recent approvals of formula rates have been for gas distribution, as this is one means to avoid the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized legislatively for electric utilities in Arkansas.

Figure 9: Current Retail Formula Rate Precedents by State



[11] For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 8

Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2013-open	Dockets 18117 and 18416 (August 2013)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2014-2018	Dockets 18406 and 18328 (December 2013)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2013-2017	Docket 28101 (August 2013)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017, extended through 2019	Case 12-0001 (September 2012) and Public Act 098-1175
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017, extended through 2019	Case 11-0721 (May 2012) and Public Act 098-1175
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Southwestern Electric Power	Electric	Formula Rate Plan	2013-2016	Docket U-32220 (July 2014)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2011-present	Docket 05-UN-0503 (April 2011)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2014-open	Docket 2014-UN-060 (May 2014)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 6 (FRP-6)	2015-open	Docket 2014-UN-132 (December 2014)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Cause PUD 201000030 (July 2010)
OK	Arkansas Oklahoma Gas	Gas	Performance Based Rate of Change Plan	2013-open	Cause PUD 201200236 (July 2013)
SC	Piedmont Gas	Gas	NA	2005-open	Docket 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-open	Docket 2005-113-G (October 2005)
TN	Atmos Energy	Gas	Annual Review Mechanism	2015-open	Docket 14-00146 (May 2015)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2013-2017	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2007
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2014-open	Various Resolutions/Ordinances across cities in service territory including City of Tulia Ordinance 2014-03
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2012-open	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-2013	Dockets 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014, later changed to 2013	Dockets 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-2014	Docket U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-2014	Dockets U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-2011	Docket 05-UN-0503 (December 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2012-2014	Docket 12-UN-139 (May 2012)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic (cont'd)					
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-2012	Docket 07-UN-548 (December 2007)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-2014	Docket 2009-UN-388 (March 2010)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP-1)	1995	Docket 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Cause PUD U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Cause PUD 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Cause PUD 200400187 (November 2004)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2014	Docket 200800348 (April 2009)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - varying end dates	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Centerpoint Energy - Beaumont East Texas Gas Division	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

VII. Marketing Flexibility

This is a new section, added since the last survey. We've added it because we (and EEI) believe that marketing flexibility is a growing, strategic issue for EEI members. Several trends in business conditions are driving the need for more flexibility. The growth of distributed energy resources, for example, is a competitive challenge but also brings new service opportunities related to the development of distributed energy assets (e.g., designing, financing, procuring, building, fueling, and maintaining). Grid modernization is providing new functional capabilities to the grid which also create new service opportunities.[12] Examples include new reliability, network management, and transaction management services. Residential and commercial customers also have a growing interest in plug-in electric vehicles, and all retail customers have shown an interest in green power packages that can be supplied from grid-accessed resources.

New services will tend to be optional services that all customers will not want. Customers must be able to decline them; and if they do, not to incur associated costs. Competitive alternatives will be available for many of these services, and customers may have special needs that are difficult to address with standard tariffs. Thus, utilities will need to be able to respond quickly to the market. They will often be price "takers," as opposed to price "makers."

To date, regulatory precedent allowing investor-owned electric utilities to offer many of these services has been limited. This chapter is, in effect, a place holder for expected future electricity precedent.

Why Electric Utilities Need Marketing Flexibility

Of course, electric utilities have always needed flexibility in some of the markets they serve:

- Utility assets have uses in markets other than those for retail electric services. Most notably, surplus generating capacity of VIEUs can be used for sales in bulk power markets. These markets are competitive and price-volatile. Land in transmission corridors can be well-suited for nurseries. Prices utilities charge in competitive markets like these are largely decontrolled. Margins earned in these markets are shared with customers of retail electric services.
- The demand of large-load retail customers is often sensitive to the rates and other terms of service utilities offer because these customers have power-intensive technologies and/or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind are especially important to vertically integrated utilities. Discounts or special contracts for such customers are traditionally allowed but often require specific approval. Commission reviews of special contracts can take months.

[12] For an overview of modernization, see: EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 2014.

Marketing Flexibility Remedies

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to "light handed" regulation and outright decontrol. Light handed regulation typically takes the form of expedited approval of market offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rates and services with certain characteristics. Light handed regulation of optional rates and services, for example, is based on the grounds that customers are protected by their freedom not to take the service, their continued access to service under standard tariffs, and the availability of alternatives in unregulated markets. Optional offerings include tariffs open to all qualifying customers, special contracts, and discretionary value-added services. Decontrol is typically permitted only for offerings to markets where vigorous competition reigns.

Marketing Flexibility Examples: Electric Utilities

Marketing flexibility is not extensive in the electric utility industry today but there are nonetheless notable examples such as the following.

- Four Florida electric utilities have "Commercial/Industrial Service Rider" ("CISR") tariffs that allow them to negotiate contract service agreements ("CSAs") that outline discounts on the base energy and/or demand charges for large load customers who can show that they have viable alternatives to utility-provided electric service.[13] The discounted rate must cover the incremental cost of service provision and provide a contribution to fixed costs. CSAs do not need commission approval but the commission has the option to conduct a prudence review of any signed contract.

- Duke Energy offers large North Carolina customers an optional Green Source Rider service. The program allows customers that have added at least 1 MW of new load since June 2012 to apply for an annual amount of renewable energy (and the associated renewable energy certificates) over a specific term (between 3-15 years). Customers may request a particular renewable resource in their application. Duke would then negotiate a purchased power agreement on behalf of the customer or attempt to source the energy from its own assets.

[13] Florida Public Service Commission (2014), Order Approving Commercial/Industrial Service Rider Tariff, Order No. PSC-14-0110-TRF-EI.

Marketing Flexibility in Other Regulated Industries

Regulators and electric utilities considering new forms of marketing flexibility can learn from other utility industries that have experienced technological change, increased competition, and/or complex and changing customer needs. We provide here brief overviews of experience in the telecommunications, gas distribution, gas transmission, and railroad industries.

Telecommunications

Local telephone companies (aka incumbent local exchange carriers or "ILECs") control the traditional distribution networks connecting residences and businesses. The "last mile" services they provide include the interconnection needed for long-distance, data, security, paging, and mobile telephone services as well as local telephone calling. ILECs have in the last 30 years confronted extensive competition, rapid technological change, and new marketing opportunities. Challenges they have faced have many parallels to those emerging for electric utilities.

The Federal Communications Commission ("FCC") regulates interstate access services of ILECs. Other ILEC services are regulated by state commissions. In the 1980s, ILECs were still regulated using cost-of-service regulation with complex reporting and compensation schemes. This was succeeded by multiyear rate plans, often called "price cap" plans since they capped rate escalation but permitted some discounts to encourage greater system use. Price caps were often escalated using inflation – X formulas where the X factor reflected an estimate of the telecommunication industry productivity trend. Prices were separately capped for several baskets of services. This insulated customers in each service basket from discounts offered to other baskets. Insulation was heightened by the infrequency (or elimination) of rate cases and the common lack of earnings sharing. The FCC instituted price caps for interstate access services of ILECs in the early 1990s. Price caps also became commonplace in state ILEC regulation.

Marketing flexibility for ILECs has been most relevant in the following two areas.

Competition in Traditional Service Markets Some services ILECs offered became subject to mounting competitive pressure that varied with the location where service was offered. For example, by the late 1990s, competitive access providers like MFS were constructing high-speed fiber optic networks connecting office buildings in metropolitan areas. These networks allowed businesses and long-distance carriers to connect to customers while bypassing ILEC data facilities. They could also be used to transmit voice traffic, avoiding ILEC voice access charges. High regulated prices were uncompetitive in high-traffic locations where facilities-based competitors entered the market. For services subject to competitive challenges, price cap plans in many states permitted discounts to standard tariffs within certain bands (e.g., rates could rise by 5% less than the price cap index) and/or subject to pricing floors that discouraged predation and cross-subsidization. In markets where pronounced competition could be demonstrated, ILEC rates were sometimes effectively decontrolled.

Innovative Services Technological change gave rise to innovative new services [e.g., Voicemail, Centrex and high-speed data (e.g., digital subscriber loop or "DSL")] which utilize essential network assets of ILECs and cannot not practically be performed by affiliates.[14] Many of these services were deemed "information" services and were regulated by the FCC. Regulators ultimately permitted ILECs to provide a host of these services and allowed considerable pricing flexibility.

Gas Distribution

Natural gas distributors also need flexibility to address some markets that they serve. Like VIEUs, many large-load customers of gas distributors have price sensitive demands and special needs. Distributors have frequently obtained light handed regulation to respond to these challenges. Nicor Gas, for example, offers a contract service for customers taking delivery near interstate gas pipelines. Contracts are submitted to state regulators for informational purposes and are treated on a proprietary basis. Nicor has similar flexibility to enter into custom contracts with electric power generators. The Company must document to the regulator that revenues from such service exceed the incremental cost of service, thereby ensuring a positive contribution to fixed cost recovery.

Interstate Gas Transmission

Interstate pipeline companies need marketing flexibility for many reasons. Demand for a pipeline's services can be sensitive to the terms it offers due to competition from other pipelines, dual-fuel capabilities of large volume customers, the extreme variability of need for service, and other special needs. It is difficult to design standard tariffs that meet the needs of all customers. Pipelines also have their own needs, such as an interest in signing anchor shippers to long-term contracts before constructing new facilities. Since 1996, the FERC has engaged in light handed regulation of negotiated pipeline rates to individual customers who have recourse to service under a standard tariff. The FERC gives a quick turnaround to most requests for negotiated contracts. A sizable share of pipeline service is conducted under negotiated rates. A remarkable variety of rate designs have been employed.[15]

Railroads

In the railroad industry, MRPs were permitted under the terms of the Staggers Railroad Act of 1980. Railroads were given a freer hand to respond to competition from truckers, waterborne carriers, and other railroads. The railroads also used marketing flexibility to offer discounts to customers that reduced their cost by assembling their own unit trains and not requesting pickups or deliveries in remote locations.

MRPs are less common today in the railroad and telecom industries. However, marketing flexibility continues under new regulatory systems that share with MRPs the attribute of protecting core customers without linking a carrier's rates closely to its own cost. Railroads have recently used this flexibility to compete for traffic from new oil field developments.

[14] Centrex service, which provided businesses features like call-waiting, auto attendant, voicemail, 4-digit extension dialing and conference calling, could also be sourced by purchasing or leasing a private branch exchange ("PBX"), a private network platform that enabled these features.

[15] See, for example, Comments of the Interstate Natural Gas Association of America in FERC Docket PLO2-6-000, September 2002.

VIII. Conclusions

Regulation of North American energy utilities is evolving to better meet the needs of utilities and their customers in a rapidly changing world. Innovation continues, while some older forms of Altreg such as multiyear rate plans are having a renaissance.

The variety of Altreg approaches that have been established reflects the varied circumstances of utilities. Some are vertically integrated, while others are more specialized wire companies. Capex needs and trends in average use vary greatly. Regulatory traditions also vary across the US and other advanced industrial countries.

No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying challenges increases the chance that an approach has already been tried that would work well, with some adjustments, in new situations. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to achieve compensatory rates of return while making needed investments, improving efficiency, and developing more market-responsive rates and services. Regulation can be streamlined, and utilities can be encouraged to embrace cost-effective DERs. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which kinds of Altreg might work best in their situation.

Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates

RESPONSE TO PC51 REQUEST FOR COMMENTS

PREPARED FOR

Joint Utilities of Maryland

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March 29, 2018

THE Brattle GROUP

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Table of Contents

I. Introduction

The Brattle Group was asked by the Joint Utilities of Maryland[1] to apply our ongoing research of regulatory issues and processes in order to answer questions posed by the Maryland Public Service Commission ("Commission") with respect to the Commission's issuance of its Notice of Technical Conference: *Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*.

In its Notice of Technical Conference on Alternative Forms of Rate Regulation, the Commission asked six primary questions concerning:

1. The manner in which those state regulatory commissions determined which alternative rate plans were acceptable;
2. The implementation period to transition from one form of regulatory rate making principles to the alternative rate plan;
3. Any restrictions placed by other state regulatory commissions on the use of alternative rate plans, including whether a utility can switch between alternative rate plans in subsequent cases;
4. The frequency by which the utility may file for rate increases under an alternative rate plan;
5. How reconciliations and refunds may be made when the utility is using a forecasted test year or other forecasted methodology; and
6. The impacts on the ratepayers resulting from the use of the alternative rate plans.

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1 The Joint Utilities are Baltimore Gas and Electric Company, Delmarva Power & Light Company and Potomac Electric Power Company.

In addition to these six questions, the Commission posed a seventh request for information related to whether state commissions with alternative rate plans required additional staff resources or staff with different skills than previously utilized.

This report focuses on three forms of alternative rate plans (or alternative regulatory mechanisms)[2]: future test years ("FTY"), formula rates ("FR"), and multi-year rate plans ("MRPs"). **Future (or forward) test years** seek to minimize imbalances in revenue recovery by setting rates based on best projections, rather than history. **Formula rates** are regulatory mechanisms that allows for periodic adjustment of rates based on forms of "true-ups." The use of formula rates improves alignment of revenue recovery to utility costs by allowing rates to more closely track changes in utility operations. **Multi-year rate plans** are designed to improve overall utility performance in controlling costs. Under the MRPs, rate cases occur less frequently (typically three or so years in the U.S., but as many as eight under the U.K.'s Revenue = Incentives + Innovation + Outputs, or RIIO plan).

The questions raised by the Commission are appropriate to ask as it is considering the impact of enhancement to its current regulatory regime, and as it considers joining the other states that have adopted alternative regulatory plans. Most of the questions raised are answerable based on the record established in state regulatory proceedings. Two questions, however, are less directly discernable. First, the manner in which state regulatory commissions determine that the benefits of adopting an alternative regulatory mechanism is typically not clearly spelled out in state commission orders and decisions. Second, retrospectively determining the impacts on ratepayers involves complex empirical analysis which has not been undertaken by most (or possibly any) state regulators. Nonetheless, we answered these more difficult questions as best possible based on regulatory records and interviews with staff.

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2 We use the alternative rate plan and alternative regulatory mechanism terminology interchangeably in this report.

The Brattle Group has undertaken a variety of surveys and studies concerning the scope and motivations underlying the adoption of alternative regulatory mechanisms, which we used to answer the Commission's questions. We also took a "deep dive" approach by selecting ten utilities across different jurisdictions for review. These ten jurisdictions were selected to include a mix of states that have relatively recently implemented an alternative regulatory mechanism as well as jurisdictions with commissions typically considered to be leaders in their field.[3] Within each jurisdiction, we selected a single utility to illustrate how the alternative regulatory mechanism was selected and implemented (see

Table 1). While most of these jurisdictions employ multiple alternative regulatory mechanisms (typically a future test year in conjunction with either formula rate or MRP), we have focused on the mechanisms shown in

Table 1.

Table 1: Jurisdictions and Utilities Reviewed

State	Utility	Utility Short Name	Alternative Rate Plan Type
New Mexico	Public Service of New Mexico	PSNM	FTY
Arkansas	Entergy Arkansas	Entergy	FR
Illinois	Commonwealth Edison	ComEd	FR
Louisiana	Southwestern Electric Power Company	SWEPCo	FR
Florida	Florida Power and Light	FPL	MRP
Hawai'i	Hawai'ian Electric Company	HECO	MRP
New Hampshire	Public Service Company of New Hampshire	PSNH	MRP
New York	Consolidated Edison	ConEd	MRP
North Dakota	Nothern States Power	NSP	MRP
Washington	Puget Sound Energy	PSE	MRP

Section II of this report focuses on the initial implementation of alternative rate plans and commission staffing requirements for alternative rate plans (Questions 1 and 7). Section III reviews

[3] Several jurisdictions have long-running alternative rate plans, such as Alabama Power's use of formula rates, which was initiated in 1982. See "Case Study of Alabama Rate Stabilization and Equalization Mechanism", Edison Electric Institute, June 2011.

the structural and implementation details of each utility's alternative rate plan (Questions 2 through 6).

II. Commission Processes to Enable Alternative Rate Plans

Regulatory approval of an alternative regulatory mechanism is based on the commission's perspective on the relative risks and benefits of the mechanism or plan, combined with legal and/or regulatory considerations. While described as "alternative," the regulatory mechanisms considered here have recently become mainstream, with a majority of states allowing the use of multi-year rate plan, forward test year, or formula rate, as shown in

Table 2.[4] This section discusses the processes through which alternative regulatory mechanisms have been approved, and staffing requirements deemed necessary in order to effectively implement such plans.

[4] Counting the usage of alternative regulatory mechanisms is not as straightforward as it may sound. States are frequently served by multiple utilities, each of which may be regulated under a different mix of mechanisms. Furthermore, state regulators may not always refer to similar mechanisms by the same names, which means that some judgement needs to be applied to draw comparisons across jurisdictions. For example, California and New York both set rates for a three-year rate case cycle, which we consider to be an MRP / incentive regulation approach. However, regulators there refer to it as a three-year general rate case (GRC) cycle. Also, regulators in Oklahoma refer to certain true-up based rate plans (applied to gas LDCs) as performance rate plans; we categorize them as formula rates.

Table 2: Survey of States with Alternative Regulatory Mechanisms for Electric Utilities (*) (includes Washington, D.C.)

Mechanism		Number of States
Multi-Year Rate Plans	[1]	20
Formula Rates	[2]	11
Forward Test Years	[3]	25

Sources and Notes:

(*) Count for formula rates includes states that have also allowed formula rates for gas utilities.

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

[2] Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute); Arkansas Public Service Commission, "Formula Rate Plan Rider," Docket No. 16-052-U, Order No. 8, Approved May 18, 2017. Includes 5 states (Georgia, Oklahoma, South Carolina, Tennessee, and Texas) that have formula rates only for gas utilities.

[3] Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute). S&P Global Market Intelligence Regulatory Research Associates, "Arkansas Regulatory Review," November 4, 2016. Indiana Code Title 8, Utilities and Transportation § 8-1-2-42.7.

A. Alternative Regulatory Mechanisms

Question 1: the manner in which those state regulatory commissions determined which alternative rate plans were acceptable;

Overall, the application of alternative rate plans on a state-by-state or utility-by-utility basis reflects a combination of the commission's view on the operating environment facing the utility, potential risks and rewards, and both regulatory and legal requirements. However, the scope of a state regulatory commission's authority to implement such plans may be constrained by statute or regulatory precedent. Thus, a commission's decision whether or not to implement an alternative regulatory mechanism may require that state law and/or regulatory code be modified.

State regulatory commissions can readily modify regulatory code when they find potential merit in an alternative regulatory mechanism, if the constraint lies within existing regulatory code. On the other hand, legislation may be required when existing law is explicit on such matters or when statutes specify the options that may be considered by state regulators. Our review indicates that state commissions have typically enabled the use of future test years without legislative input.

However, there are examples (such as New Mexico), where modification to regulation and implementation of a future test year required passage of legislation.[5]

In our survey of ten jurisdictions (listed in Table 3), two of the three states with formula rates (Arkansas and Illinois) required passage of enabling legislation. In contrast, as shown in

Table 3, none of the states in which regulators approved MRPs required additional legislation, although this is almost certainly not universally the case.[6]

Table 3: Enabling Body (Commission or Legislative) of Alternative Regulatory Mechanisms

State	Utility Short Name	Alternative Rate Plan Type	Method of Approval
New Mexico	PSNM	FTY	Legislative
Arkansas	Entergy	FR	Legislative
Illinois	ComEd	FR	Legislative
Louisiana	SWEPCo	FR	Commission
Florida	FPL	MRP	Commission
Hawai'i	HECO	MRP	Commission
New Hampshire	PSNH	MRP	Commission, Judicial
New York	ConEd	MRP	Commission
North Dakota	NSP	MRP	Commission
Washington	PSE	MRP	Commission

From a process perspective, our review indicates that utilities are typically the initiators of regulatory modification; state regulatory commissions typically respond to a request from a utility when approving a specific alternative regulatory mechanism. For example, the District of Columbia Commission's order allowing Pepco DC to file for alternative regulatory mechanisms

5 Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 4.

6 In implementing an MRP, the New Hampshire Public Utilities Commission did not specifically reference a legislative precedent, but cited both prior commission precedent and a judicial case related to attrition relief. State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 31.

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explicitly included the two mechanisms first proposed by the utility.[7] There have also been stakeholder processes initiated by commissions to investigate alternative regulatory mechanisms, for example the ongoing performance based regulation process in Hawai'i, to thoroughly vet different approaches and incorporate input from all stakeholders. However, these processes are relatively uncommon in our experience due to their prohibitive implementation cost.

Commissions generally will examine whether the alternative rate plan will result in a just and reasonable rate considering a number of factors involved in setting utility rates. Broadly speaking, the process typically involves consideration of various stakeholder perspectives and filing of testimony to discover plan details, potential impacts on the ratepayers and the utility business. Customer costs, utility financial integrity, utility performance and administrative burden of the plan may all be relevant concerns to consider. To the extent that there are jurisdictional policy goals (i.e. commitment to grid modernization, increased DER penetration or clean energy targets), they are also taken into account in assessing how the proposed regulatory mechanism helps achieve these goals. The end goal is to agree on an alternative mechanism that will be enabling for the utilities as they pursue investments to meet the needs of an evolving grid, while balancing customer rate impacts and ensuring service quality is maintained.

Excerpts from the settlements approving alternative rate mechanisms for utilities in our survey provide some color around the nature of commissions' considerations when determining their acceptability:

> "The Stipulation and Settlement appears to provide FPL's customers with a degree of stability and predictability with respect to their electricity rates while allowing FPL to maintain the financial strength to make investments necessary to provide

7 Public Service Commission of the District of Columbia, Order No. 18846, Formal Case No. 1139, July 25, 2017, pp. 184-185, 187.

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> customers with safe and reliable power.[…] In addition, we recognize that the Stipulation and Settlement reflects the agreement of a broad range of interests[.]"[8]
>
> "Moreover, it provides for a series of rate increases intended, among other things, to ensure that the erosion of earnings attributable to attrition will not compel the Company to seek another rate increase in a short time. The settlement agreement offers this protection without unduly burdening customers and without removing all risk from the Company and its shareholders to operate an efficient business. Further, the term of the agreement is long enough to allow the rate changes to be meaningful, without being so long as to lock-in customers or the Company to a losing strategy for an unreasonable period. It also provides some protection for both customers and the Company from over- or under-earning."[9]

As discussed later, and at length in similar reports,[10] alternative regulatory mechanisms are not monolithic. The components of the mechanisms can be structured in a variety of ways. Similarly, a regulatory plan applied to a given utility reflects its unique circumstances as well as jurisdiction specific policy considerations. In practice, this means that a plan may include one or more alternative regulatory mechanisms (e.g. future test year in a multi-year rate plan with an earnings sharing mechanism) in combination with an overall rate of return methodology.

B. Commission Staffing Requirements

Question 7: The Commission also is interested in whether other states, in implementing alternative rate plans, required additional staff resources or staff with different skills that previously utilized prior to implementing.

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8 Florida Public Service Commission, Order No. PSC-05-0902-AS-EI, Docket Nos. 050045-EI and 050188-EI, September 14, 2005, p. 6.

9 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 41.

10 See for example: Mark Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015 (prepared for Edison Electric Institute).

The three alternative regulatory mechanisms considered here (future test years, formula rates, and MRPs) are all extensions of traditional rate making rather than a fundamental shift in regulatory approach. As a result, the core skills required by commission staff to implement alternative regulatory mechanisms are skills already associated with traditional regulatory plans. In our survey, we did not find staffing concerns cited in relation to the evaluation or implementation of alternative rate plans by commission staff testimony or in final orders for any of the utilities. While possible that these concerns were expressed in a different forum, the lack of commentary appears to indicate that staffing and resources have not been primary concerns for the commissions.

It is true that when commissions transition from the traditional model to an alternative regulatory mechanism, staff may need additional training. For instance, when transitioning from historical to future test years, staff will likely need additional training to gain skills in evaluating cost projections. NRRI's 2013 survey of commissions with regard to their use of future test years found that:[11]

> "Some commissions reported that they had to acquire new staff expertise. Almost all commissions replied that a FTY took little if any time away from addressing other rate case topics. Only one respondent mentioned that given the limited time for rate cases and the complexity of evaluating forecasts, parties may have insufficient time to assess a utility's forecasts."

In our survey, multiple commissions cited existing staffing concerns as a motivation to enact an alternative rate plan. When a utility's operating environment is changing rapidly (*e.g.*, changes in load, increases in costs, etc.), a historic test year can be out-of-date before the rate case settles, and the utility will have to refile rate cases frequently to update the test year. Frequent rate case filings

[11] Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 11.

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pose a burden to commission staff, as illustrated by the Washington commission's order regarding PSE's multi-year rate plan:[12]

> "An important policy objective underlying our decision is to relieve all stakeholders and the Commission from the burdens of almost continuous general rate case proceedings that have characterized our utility regulation during recent periods."

Plans that span multiple years, such as MRPs and formula rates, remove the need for full annual rate case filings and, in some cases, implement a mandatory stay-out. Some commissions, such as California, Hawai'i, and New York, have adopted general rate case cycles rather than implementing alternative rate plans on a utility-by-utility basis. That is, they have determined that all utilities will be on a similar, multi-year rate case cycle. The filing dates for utilities are staggered to spread the burden of work on the commission. Future test years mitigate the need for frequent filings as the costs included in the test year are more representative of the utility's operating environment. However, a future test year is a short-term fix, to the extent that the utility's operating environment will continue to change, as the future test year only takes into account a single year in the evolution.

Alternative rate plans that involve annual reconciliations (*e.g.* formula rates) do require filings that require commission staff review. However, these filings are intended to be formulaic, and typically involve pre-determined filing requirements (and formats) and are somewhat limited in scope and timing. For example, ComEd recently completed its eighth filing under a formula rate mechanism. The ROE is determined formulaically (580 basis point premium above the 12-month average U.S. Treasury bond yield) and the cost of capital is then updated to reflect the utility's actual capital structure. The commission does continue to have the authority to investigate the prudence and reasonableness of utility investments, but the overall process is less time-intensive than when all

[12] Washington Utilities and Transportation Commission, Order 07, Docket Nos. UE-121697 and UG-121705 (consolidated) and Docket Nos. UE-130137 and UG-130138 (consolidated), June 25, 2013, p. 8.

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parameters are up for potential challenge. ComEd's recent rate case lasted 6 months from the initial filing in April 2018 to the final order in December 2018.[13]

We have also informally surveyed several staff members from three of the ten states/utilities reviewed in our report. One staff member stated that "*it is not that the alternative regulatory models are driving the need for more staff and differently skilled staff. The major driver is the technological change: cost reductions in new distributed technologies and greater urgency to address climate goals. The alternative regulatory models are more a reaction, rather than the cause for the new needs.*" Another staff member indicated that "*at no time have additional Staff been contemplated in response to the needs of alternate regulation. What is possible is that occasionally and within narrowly defined financial limits we may be able to bring in consultants to support additional needs.*"

III. Alternative Regulatory Mechanisms in Action

To answer specific questions related to the implementation of alternative regulatory mechanisms, we focused on ten individual utility plans. When possible, we selected the electric utility with the earliest use of the alternative regulatory mechanism in order to capture information on the transition to its use.

A. Transition to Alternative Regulatory Mechanisms

Question 2: the implementation period to transition from one form of regulatory rate making principles to the alternative rate plan;

13 S&P Global Market Intelligence, "RRA Regulatory Focus: Commonwealth Edison," January 4, 2019.

Continued on next page

The transition period to an alternative regulatory mechanism depends to some extent on the origin of the proceeding and enabling body. For the utilities in our survey, the regulatory processes to approve alternative rate plans were either comparable in length to or slightly longer than the process under a traditional regulatory mechanism (see Table 4).[14] However, for those cases where legislative action was required, the legal amendment process typically precedes a filing under the new regulatory mechanism and makes the timelines more uncertain, as discussed in more detail below.

There are a few exceptions with shorter or longer regulatory process timelines: on the extremes are 1) Puget Sound Energy (PSE) in WA, which filed its MRP under an expedited rate case framework approved in the prior rate case filing,[15] and 2) Southwestern Electric Power Company (SWEPCO) in LA, for which the process was drawn out by a series of motions to delay.[16]

Table 4: Regulatory Process Timelines for Alternative Rate Plans

State	Utility Short Name	Alternative Rate Plan	Initial Filing	Final Order	Duration (Months)
New Mexico	PSNM	FTY	08/2015	09/2016	13
Arkansas	Entergy	FR	04/2015	02/2016	10
Illinois	ComEd	FR	11/2011	05/2012	7
Louisiana	SWEPCo	FR	01/2003	04/2008	64
Florida	FPL	MRP	03/2005	09/2005	6
Hawai'i	HECO	MRP	07/2010	06/2012	23
New Hampshire	PSNH	MRP	06/2009	06/2010	12
New York	ConEd	MRP	05/1991	04/1992	12
North Dakota	NSP	MRP	12/2012	02/2014	15
Washington	PSE	MRP	02/2013	06/2013	5

Notes: These timelines refer to each utility's initial alternative rate plan filing.

14 The Edison Electric Institute reports a 10-month average regulatory lag (defined as the time between a rate case filing and decision) since industry restructuring. Edison Electric Institute, "Rate Review Summary: Q2 2018 Regulatory & Financial Update."

15 S&P Global Market Intelligence, "Puget Sound Energy, Inc.: WA: D-UE-130137 | Rate Case Profile."

16 See Louisiana Public Service Commission, Docket U-23327 Subdocket A (documents): http://lpscstar.louisiana.gov/star/portal/lpsc/PSC/DocketDetails.aspx?DocketId=363b9e78-800a-4dfc-94de-839f05db879f.

In cases where legislative action is required to enable the alternative regulatory mechanism, the legal amendment process can add uncertainty to the overall timeline. For example, when ComEd first sought to implement a formula rate plan in conjunction with its infrastructure investment commitments under the 2011 Energy Infrastructure Modernization Act (Senate Bill 1652), the filing was preceded by then-Governor Pat Quinn's veto of SB 1652, and a subsequent override by the Illinois Legislature. The revised bill (HB 3036) that was eventually signed by the Governor (in December 2011) had not yet been approved when ComEd filed its formula rate plan under a concurrent regulatory docket.[17] However, the regulatory approval timeline itself was fairly concise: ComEd's initial filing was submitted in November 2011 and the proceeding was decided on in May 2012. Similarly, in Arkansas, Entergy filed its rate case in April 2015, the same year as changes to the Arkansas Code. The order approving Entergy's formula rate plan was finalized in February 2016 about 10 months after the initial filing. Entergy's first annual filing for a true-up was in July 2016.[18]

The New Mexico legislature allowed the use of future test years in 2009. The first rate case including a future test year (for Southwestern Electric Power Co.) was filed in 2012 and settled 15 months later.[19] Although the time period between New Mexico enabling future test years and the settling of its first case is extended, the time period is not representative of all, or even most, states. For example, Michigan's legislature enabled the use of future test years in 2017,[20] and Consumers Energy filed a rate case in March 2017, using a projected test year, that was finalized in March 2018.[21]

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17 S&P Global Market Intelligence, "Electric Capital Investment Legislation Signed by Illinois Governor," January 4, 2012.

18 S&P Global Market Intelligence, "Entergy Arkansas, LLC: AR: D-15-015-U | Rate Case Profile."

19 S&P Global Market Intelligence, "New Mexico Public Regulation Commission."

20 S&P Global Market Intelligence, "Michigan Public Service Commission."

21 S&P Global Market Intelligence, "RRA – Rate Case Final Report Consumers Energy Co.", August 9, 2018.

The use of a pilot program, or other transition mechanism, are commonly used in utility regulation to limit the scope of a new approach (e.g., limiting to a subset of utility expenditures) or scale of the approach (e.g., limiting the time span of the program) when the costs or benefits of an approach are uncertain. Other transition mechanisms can include phase-ins, whereby the scope of a program is gradually increased, or the use of additional reporting (monitoring), which can help the commission to understand how a mechanism may work in practice prior to adding financial incentives. Reporting-only mechanisms have been used, for example, when introducing emerging performance incentive mechanisms with novel scopes and metrics.

Based on our review of jurisdictions, pilot programs are not commonly used for the alternative rate plans considered. Specifically, pilot programs were not used for any of the utility rate plans surveyed. We are familiar with one instance of a formula rate plan being first implemented on a trial basis, which was then continued on a non-trial basis.[22] Because many alternative rate plans are limited in term, they already take on the structure of a time-limited pilot program. This time limitation provides a defined point for re-evaluation of the plan's performance. This was the view adopted by the New Hampshire commission in its approval of PSNH's MRP:[23]

> "We also note that though this is not designated as a "pilot" or similar program, see id. at 15, the limited term of the settlement agreement effectively renders it a short term program. We find this limitation important because a great deal may change during the term of the settlement agreement and it may be advisable to revise or eliminate items such as this in the future."

Commissions may institute additional reporting requirements during a transition to improve confidence in a new regulatory plan, notably those that include the use of projections in

22 Corporation Commission of the State of Oklahoma, Order No. 499253, Cause No. PUD 200400187, November 24, 2004, p. 8.

23 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 32.

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determining the revenue requirement. Commissions with projected test years (or other forward looking approaches such as MRPs) frequently request both historical and future test year operational information in the utility filing.[24] For example, Wisconsin requires utilities to file historical sales, O&M expenses, rate base, and working capital balances.[25] This approach, of requesting both the traditional and forward-looking approaches, can also be used to compare regulatory plans.

B. Transitions between Regulatory Plans

Question 3: any restrictions placed by other state regulatory commissions on the use of alternative rate plans, including whether a utility can switch between alternative rate plans in subsequent rate cases;

Commissions do not typically require utilities to maintain an alternative rate plan in future rate cases, and utilities can and do switch between traditional and alternative rate plans. The approach for regulating a utility may change over time. For example, Entergy New Orleans was regulated under formula rates from 2004-2006 and then from 2010-2012.[26] Likewise, PSNH was regulated under an MRP from 2010-2015 and then returned to traditional rate making as the utility transitioned through the sale of generation assets.[27] These transitions between regulatory approaches may reflect changes to the underlying operating environment that prompted the use of the alternative regulatory plan or reflect other exogenous factors. We are unaware of any jurisdictions in which utilities have switched between multi-year rate plans and formula rates.

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24 Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 9.

25 *Ibid.*, p. 32.

26 Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update", Edison Electric Institute, November 11, 2015, Table 8.

27 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010.

State of New Hampshire Public Utilities Commission, Order 25,920, Docket No. DE 14-238, July 1, 2016.

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Excluding utilities that are on a general rate case cycle (*i.e.*, HECO and ConEd), the utilities in our survey were not required to maintain formula rates or MRPs beyond the current term.[28]

The ability of a utility to transition between traditional rate making and an alternative rate plan (typically formula rates or multi-year rate plans), is bounded by stay-out requirements and mandatory refiling dates. Stay-out requirements prevent utilities from refiling for a change in base rates (or regulatory plan) for a certain number of years, typically 3-5 years. Stay-out requirements frequently include clauses to account for unanticipated events with significant financial impact and may allow a utility to refile if earnings are below a certain threshold. For example, PSNH's plan allowed the utility to refile if its allowed ROE dropped below 7%,[29] and NSP's plan included the ability to file for increased rates if an exogenous event results in a revenue requirement impact of at least $1.5 million.[30] As shown in **Error! Reference source not found.**, all of the MRPs in the survey included mandatory stay-outs. At the end of the plan's term, the utility may be required to file a general rate case.[31] This mandatory refiling allows for typical rate case reviews as well as modifications to alternative rate plans.

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28 None of the orders included such a requirement. The Louisiana PUC explicitly confirmed that it was up to the utility to re-propose a formula rate in its next general rate case.

29 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, p. 9.

30 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 33-34.

31 If a utility is not required to file, rates are typically frozen at the level of the last year of the term.

Table 5: Rate Case Filing Restrictions and Requirements for Surveyed Utilities

State	Utility Short Name	Alternative Rate Plan Type	Mandatory Stayout?	Mandatory Refiling Date?	Required Continuance of Alternative
New Mexico	PSNM	FTY	X*	–	–
Arkansas	Entergy	FR	–	X	–
Illinois	ComEd	FR	–	X	–
Louisiana	SWEPCo	FR	–	X	–
Florida	FPL	MRP	X*	–	–
Hawai'i	HECO	MRP	X*	X	X
New Hampshire	PSNH	MRP	X*	X	–
New York	ConEd	MRP	X	–	X
North Dakota	NSP	MRP	X	–	–
Washington	PSE	MRP	X	X	–

Notes: (*) indicates that there are off-ramp provisions that allow the utility to refile for a general rate case under certain conditions. PSNM has a mandatory stay-out that may not be related to the future test year.

C. Frequency of Rate Changes and Reconciliation of Forecasts

Question 4: the frequency by which the utility may file for rate increases under an alternative rate plan;

Question 5: how reconciliations and refunds may be made when the utility is using a forecasted test year or other forecasted methodology;

Reconciliations between utility forecasted and actual costs, revenues, or a combination thereof are common across a variety of regulatory mechanisms. Cost trackers are a regulatory mechanism used in 45 states that can provide for a reconciliation between forecasted expenditures and actuals. Likewise, decoupling can provide a true-up between forecasted and actual revenues, typically on a per-customer basis. These mechanisms, including riders and decoupling, can, and frequently are, used in combination with future test years, formula rates, and multi-rate year plans.[32] We have not included these reconciliations in our discussions of alternative regulatory mechanisms.

[32] Because decoupling and formula rates accomplish similar goals, the two are not used in combination.

Utilities regulated under formula rates and MRPs typically have the potential for annual rate changes based upon pre-approved changes to the revenue requirement, reconciliations related to ROEs, and reconciliations between forecasted and actual expenditures. Customers may experience rate decreases, rate increases, or no change in rates on a year-to-year basis depending on the design of the plan and the utility's performance. In our survey of utility rate plans, all nine with a formula rate or MRP included the potential for annual rate changes,[33] these potentials for rate changes and reconciliations are summarized in Table 6.

Table 6: Reconciliations in Surveyed Alternative Rate Plans

State	Utility Short Name	Alternative Rate Plan Type	ROE Reconciliation: Over Earning	ROE Reconciliation: Under Earning	Reconciliation (Non-ROE): CapEx	Reconciliation (Non-ROE): OpEx
New Mexico	PSNM	FTY	X*	–	–	–
Arkansas	Entergy	FR	X	X	–	–
Illinois	ComEd	FR	X	X	–	–
Louisiana	SWEPCo	FR	X	X	–	–
Florida	FPL	MRP	X	– *	X	–
Hawai'i	HECO	MRP	X	–	–	–
New Hampshire	PSNH	MRP	X	–	X	–
New York	ConEd	MRP	X	–	X	X
North Dakota	NSP	MRP	X	–	–	–
Washington	PSE	MRP	X	–	–	–

Notes: (*) PSNM has an earning sharing mechanism as part of a rider that predates the future test year. If the ROE for FP&L falls below 9.6%; FP&L may file with the Commission for an increase in rates.

Under formula rates, base rates are typically adjusted based on ROE reconciliations. Backward true-ups compare the utility's earned ROE for the historic year compared to an allowable range (deadband) for the earned ROE. If the utility's ROE is outside the deadband, then rates are either increased or decreased to adjust the utility rates to allow the utility to make-up the difference between the target ROE and the earned ROE. The target ROE may be the allowed ROE (e.g., ComEd and Arkansas), the edge of the deadband, or some percentage of the difference between the allowed and earned ROE (e.g., Louisiana). As the true-up is on the utility, both capital and

[33] At least one MRP, the NSP MRP included a year with a mandatory base rate increase moratorium. State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 5.

operating expenditures are included. In addition, formula rates also include a forward adjustment. The forward adjustment compares a projected ROE to the allowed ROE range. If the projected ROE falls outside the range (outside the deadband) then rates are adjusted on a prospective basis to bring projected ROE back to the target ROE.

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. Of the six MRPs included in our survey, three include some type of CapEx reconciliation and only one includes OpEx reconciliations. CapEx reconciliations can be made on the basis of a single investment (e.g., generation plant), investment type (e.g., grid modernization), or across all investments (e.g., distribution system plant). The CapEx reconciliation for FPL focuses on one plant and an allowance for investment in solar generation. The CapEx reconciliations for ConEd and PSNH were based on distribution plant balances. ConEd has multiple OpEx reconciliations including those for property taxes and non-officer variable pay.[34] In addition to the CapEx and Opex reconciliations, MRPs frequently include earning sharing mechanisms in which earnings above earned ROEs (and a deadband) are returned to customers. Each of the MRPs in our survey include an earning sharing mechanism; more broadly 10 of 17 MRPs included earning sharing mechanisms in a 2015 study.[35]

In our survey of MRPs, ConEd has the most reconciliations, with more than fifteen reconciliations across CapEx and OpEx including: property taxes, contractor costs, pensions and other post-employment benefits, environmental remediation, long term debt costs, and a portion of managerial pay. For the majority of the aforementioned categories, the credits or surcharges resulting from the reconciliation are deferred over the term of the plan and revenue requirement

34 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35, 42.

35 Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update", Edison Electric Institute, November 11, 2015, Table 7.

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impacts addressed in future rate proceedings.[36] For CapEx, the commission considers net plant balance. If ConEd under invests based on net plant balances on average across the three years, the revenue requirement will be deferred for ratepayers.[37]

Future test years may be used with other regulatory mechanisms that include reconciliations (including MRPs, formula rates, and decoupling), which makes identifying reconciliations related to the use of a future test year in isolation difficult. In the 2013 NRRI survey of future test years, 7 of the 14 utilities indicated that no reconciliations were used.[38] The remaining utilities identified reconciliations resulting from decoupling, ROE reconciliations (related to their existing formula rate plans), reconciliations resulting from MRPs, and rider/tracker reconciliations.[39]

Mechanically, annual adjustments made during the term of the alternative regulatory mechanisms are frequently made through riders. For example, in Louisiana and Arkansas, changes to rates resulting from the ROE true-ups are made exclusively through riders. Likewise under Public Service of Colorado's MRP, sharing of over-earnings would flow through to customers through a rider.[40] By contrast, ConEd delays most reconciliations to the next rate case.[41]

D. Impact on Ratepayers

The impact on ratepayers from the implementation of one or more alternative regulatory mechanisms is difficult to discern, mainly because changes in rates are driven by underlying costs

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36 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35.

37 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, pp. 28-29.

38 Ken Costello, "Future Test Years: Evidence from State Utility Commissions", National Regulatory Research Institute, October 2013, p. 51-52.

39 New York stated that in a one-year litigated case, additional expense categories can be subject to true-up including pension, other post-employment benefits, environmental costs, storm costs, etc.

40 Colorado Public Utilities Commission, Advice No. 1672, Docket 14AL-0660E.

41 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, pp. 28-29, 35-50.

and could have happened under any regulatory approach. Determining whether an increase in rates was caused by the adoption of an alternative rate mechanism requires the development of a counterfactual ("but for") case, i.e., what would have happened to rates if the alternative regulatory mechanism had not been adopted. For example, in Illinois, Commonwealth Edison (ComEd) was required to undertake a grid modernization initiative that involved substantial capital expenditures. It is inaccurate to conclude that the utility incurred grid modernization expenditures because of the formula rate plan; ComEd would have most likely proceeded with the capital program (as it was recognized as a priority for policymakers), and the related costs would have made their way into rates. To our knowledge, empirical studies that estimate correlation between alternative rate plans and an increase or decrease in customer rates, other factors held constant, have not been conducted.[42] However, regulators provided their own assessments of the merits and benefits of alternative regulatory mechanisms at the conclusion of the plan's term. State regulators opted to continue with the alternative regulatory mechanisms in seven of the ten cases that are included in our survey, suggesting that they found the subject plans to be consumer beneficial.

Under traditional regulation, the result of increasing underlying investment can be rate shock, as those new investments are incorporated into rate base. One feature of multi-year rate plans and formula rates is that investments can be integrated into the revenue requirement over time, or rate increases can be spread over the plan period. The gradual nature of rate increases can mitigate the rate shock that would have occurred under traditional regulation.

[42] Even a largely academic study that addresses the impact of regulatory regime on prices (Tooraj Jamasb and Michael Pollitt, "Incentive Regulation of Electricity Distribution Networks: Lessons of Experience from Britain," June 19, 2007) does not fully provide a "but for" case.

IV. Appendix – Case Studies

A. Entergy (Arkansas)

Entergy (Arkansas) – FR	
Term	2016 – 2020, inclusive (Docket: 15-015-U; Order No. 18)
Approval	2015 legislation (the Formula Rate Review Act)
Pilot/Transition?	No
Annual Base Rate Increases?	Includes an annual filing for ROE reconciliation. Rates are adjusted through the formula rates rider included in the Entergy tariff and are limited to a change of 4% each year.[43]
Mandatory Stay-Out?	N/A
Mandatory Refiling?	Entergy must file for a request to extend the formula rate plan beyond 2020. Formula rate terms are limited to five years by the enacting legislation;[44] not required to be under the same plan type.
Reconciliation between Actual and Forecasts	ROE reconciliation: includes a forward looking adjustment and a backward-looking true-up mechanism; the return on equity is subject to a +/- 50 bps deadband (termed Target Return Rate). Outside the deadband, the ROE is adjusted to reach the allowed ROE subject to the 4% cap on change in revenues on a customer class basis.[45]

43 Arkansas Public Service Commission, Order No. 19, Docket No. 15-015-U, March 21, 2016, Rate Schedule No. 44, Formula Rate Plan Rider, 44.5.4.

44 AR Code § 23-4-1208 (2015).

45 Arkansas Public Service Commission, Order No. 19, Docket No. 15-015-U, March 21, 2016, Rate Schedule No. 44, Formula Rate Plan Rider, 44.5.2.

Arkansas Public Service Commission, Application, Docket No. 16-036-FR, July 6, 2018, p. 15.

B. Florida Power & Light

Florida Power & Light - MRP	
Term	Initial Plan: 2006 - 2009 (Docket: 050045-EI, Order No. PSC-05-0902-S-E1) Current Plan: 2017-2020 (Docket: 160021-El; Order Approving Settlement)
Approval	Commission[46]
Pilot/Transition?	No
Annual Base Rate Increases?	Authorized to implement stepwise revenue increases effective January 1, 2017, effective January 1, 2018, and effective on the in-service date of the Okeechobee Unit.[47] Base rates may also be adjusted through a pre-formulated “Solar Base Rate” adjustment, which is contingent upon investment in photovoltaic facilities.[48]
Mandatory Stay-Out?	If the ROE for FPL falls below 9.6%, FP&L may file with the Commission for an increase in rates.[49]
Mandatory Refiling?	Rates will be frozen at 2020 levels until a new rate case filed (no mandatory refiling);[50] not required to be under the same plan type.
Reconciliation between Actual and Forecasts	ROE Reconciliation: pending petition to Commission and Commission approval. FP&L's authorized ROE covers the range from 9.6% to 11.6%, with rates set using a 10.55% ROE.[51] If FP&L earns a return below this range (according to a monthly earnings surveillance report stated on an FPSC actual, adjusted basis), FP&L may petition the Florida PSC to amend its base

46 House of Representatives Staff Analysis, HB7071, PCB EUS 17-01.

47 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, p. 2.

48 *Ibid.*, p. 3.

49 Florida Public Service Commission, Stipulation and Settlement, Docket No. 160021-EI, October 6, 2016, p. 16.

50 *Ibid.*, p. 11.

51 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, p. 3.

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	rates. Similarly, if FP&L earns a return above this range, any party may petition the PSC to review FP&L's base rates.[52] Other Reconciliation: for generation capital expenditures. If actual capital costs for constructing a new unit (the Okeechobee Unit) are less than projected costs, then the lower revenue requirement will be used. If the budget exceeds the projection, FP&L must seek permission to increase the allowed amount.[53] Similarly, the Solar Base Rate Adjustments allows FP&L can invest in up to 1,200 MW of solar generation subject to a cost cap and finding of cost effectiveness.[54]

52 Florida Public Service Commission, Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, December 15, 2016, pp. 16-17.

53 *Ibid.*, pp. 10, 11.

54 *Ibid.*, p. 1.

C. Hawai'ian Electric Company

Hawai'ian Electric Company - MRP	
Term	Initial Plan: - Revenue Decoupling Mechanism Established (Docket: 2008-0274; Final Decision and Order) - 2012-2014 (Docket: 2010-0080; Decision and Order No. 30505) Current Plan: 2018-2020 (Docket: 2016-0328; Order No. 35545)
Approval	Legislative/Commission
Pilot/Transition?	No
Annual Base Rate Increases?	Rate adjustment mechanism ("RAM") with three components that cover O&M, depreciation, and rate base.[55] The total annual change to the RAM is capped and cannot create a change in revenues greater than inflation (as measured by the Gross Domestic Product Price Index) multiplied by base revenues. [56] In addition to the RAM, the utility may recover capital expenditures pre-approved by the commission through the Major Projects Interim Recovery ("MPIR") mechanism. The MPIR expenditures are not included in or subject to the RAM cap.
Mandatory Stay-Out?	Yes; however, HECO may petition its commission to refile early.
Mandatory Refiling?	Yes; the utilities in Hawai'i follow a three-year general rate case cycle. Required to be under the same plan type.
Reconciliation between Actual and Forecasts	ROE Reconciliation: yes, with earnings sharing mechanism through which over-earnings are shared with customers. The earning sharing mechanism has no deadband. 9.5% < ROE < 10.5%, 25% to ratepayers; 10.5% ≤ ROE < 12.5%, 50% to ratepayers; ROE ≥ 12.5%, 90% to ratepayers.[57]

55 Public Utilities Commission of Hawai'i, Final Decision and Order, Docket No. 2008-0274, August 31, 2010, pp. 71-76.

56 This calculation excludes any revenue for fuel and purchase power expenses or revenues recovered through other surcharge or rate tracking mechanisms, plus RAM revenues less any earnings sharing mechanism credits. See Public Utilities Commission of Hawai'i, Order 32735, Docket No. 2013-0141, March 31, 2015, pp. 5-6, 93-98.

57 Public Utilities Commission of Hawai'i, Final Decision and Order, Docket No. 2008-0274, August 31, 2010, p. 106.

D. Commonwealth Edison (Illinois)

Commonwealth Edison (Illinois) – FR	
Term	Initial Plan: 2012- Ongoing (Docket: 11-0721 and Public Act 098-1175) Current Plan: Current (Docket: 18-0808)
Approval	Legislative: ComEd obtained its formula rate plan as part of the 2011 Energy Infrastructure Modernization Act (EIMA, Act 1652). Under the EIMA provisions, ComEd agreed to meet infrastructure investment targets and to create jobs: $1.3 billion over 5 years in system upgrades, modernization projects, and training facilities, plus $1.3 billion within 10 years in further T&D and smart-grid system upgrades, and 2,000 FTE jobs (or pay penalties for shortfalls in job creation).
Pilot/Transition?	No
Annual Base Rate Increases?	Includes an annual filing setting of the next year's revenue requirement (which includes ROE reconciliation for the prior year, reflecting the difference between the prior year's projected revenue requirement and actual costs incurred, with interest payments on that balance). The Commission reviews the prudence and reasonableness of ComEd's investments before approving the rate base to be used in setting revenue requirement and rates. Under the initial law granting formula rate authority, ComEd's FR would be terminated if the average annual rate increase for the years 2012 through 2014 exceeded 2.5%.[58]
Mandatory Stay-Out?	No
Mandatory Refiling?	ComEd's formula rate authority is currently in effect until 2022 (extended under the Future Energy Jobs Act (FEJA) legislation of 2017). As of March 12 2019, a bill has been approved by the House Public Utilities Committee to extend ComEd's formula rate authority through 2032.[59] Not required to be under the same plan type.

58 Under FEJA, there are now rate caps in place for each customer group.

59 Daniels, Steve. "ComEd Asks Springfield to Force You to Make a 13-year Bet on Interest Rates." Crain's Chicago Business. March 15, 2019.

Reconciliation between Actual and Forecasts	ROE Reconciliation: yes; reconciliation of earned ROE around the target (ROE = US T-bond yield monthly average over the previous calendar year + 580 bp). Until the most recent rate case, ComEd had a 100 bp collar that set the upper and lower boundaries on the actual earned ROE vs. authorized level (with an offsetting adjustment if the difference lay outside those bounds). However, FEJA authorized ComEd to eliminate the ROE collar deadband to zero bp, which it did (Docket 18-0808). The ROE is also subject to penalties (up to 30 bp) for failure to meet certain performance metrics: frequency of total system outages; frequency of "Southern Region" outages; duration of outages; service reliability; number of estimated bills; and, consumption on inactive meters, unaccounted-for-energy, uncollectible expense. Initially, the Commission approved use of average rate base for the reconciliations, with interest at a hybrid cost of long- and short-term debt). The ROE reconciliation has since been revised to use year-end rate base, starting with reconciliation of 2011 costs (based on the passage of Senate Bill 9 in 2013). Additionally, interest is now applied at a rate equal to the Illinois Commerce Commission approved pre-tax WACC for the rate year.

E. Southwestern Electric Power Company (Louisiana)

Southwestern Electric Power Company (Louisiana) –FR	
Term	Initial Plan: 2007-2009 (Docket: U-23327, Subdocket A-A; Order No. U-23327) Current Plan: 2014-2017[60] (Docket: U-32220; Order No. U-34200)
Approval	Commission
Pilot/Transition?	No; formula rates were first approved for an electric company in Louisiana in 1995 for then Louisiana Power & Light Company (now Entergy Louisiana, LLC).[61]
Annual Base Rate Increases?	The Formula Rate Plan Rider includes annual rate changes as a result of the ROE reconciliation.
Mandatory Stay-Out?	Yes; with an exception for extraordinary events as increases or decreases in costs having a net annual revenue requirement impact exceeding $5 million on a Louisiana retail jurisdictional basis and that are classified as force majeure.[62]
Mandatory Refiling?	Yes; initially required to file prior to December 2018 but received extension to May 31, 2019;[63] not required to be under the same plan type.
Reconciliation between Actual and Forecasts	ROE Reconciliation: reconciliation of earned ROE around the target with a +/- 55 bps deadband. If the earned ROE is outside the deadband, the ROE is restored to 60% of the difference between the allowed and earned ROEs.

60 Temporarily extended through 2018 in Order U-34199.

61 Louisiana Public Service Commission, Order No. U-20925, Docket No. U-20925, June 2, 1995.

62 Southwestern Electric Power Company, Tariff for Electric Service, Effective March 1, 2013, Section B, Formula Rate Plan Rider Schedule FRP, 3.B.

63 Louisiana Public Service Commission, Order No. U-34199, Docket No. U-34199, December 19, 2018, p. 2.

Continued on next page

F. Public Service Company of New Hampshire

Public Service Company of New Hampshire – MRP	
Term	July 2010 – June 2015 (Docket: DE 09-035)[64]
Approval	Judicial; Commission approval for other utility sectors[65]
Pilot/Transition?	No
Annual Base Rate Increases?	Settlement called for "step increases" throughout its term to guard against attrition. PSNH was also permitted to adjust rates, up or down, for Exogenous Events, focused on cost changes from state or federal governments, regulatory cost reassignments, or changes in accounting rules that impact rates by at least $1 million[66] and able to adjust rates if inflation exceeded 4%.[67]
Mandatory Stay-Out?	PSNH was not permitted to file for a change in base rates ("permanent distribution rates") to come into effect prior to the end of the term unless its 12-month rolling ROE was less than 7% for two consecutive quarters.[68] If all settling parties agreed and the Commission approved, the MRP could also be terminated.[69]
Mandatory Refiling?	2015 rates were scheduled to expire at the end of the term[70] and then extended; not required to file under same plan type.

64 PSNH's rates have been frozen at the 2015 levels as a result of an agreement with its commission related to divestiture of generation facilities. Under this agreement, reliability investments in the distribution system are recovered through a rider. See Eversource Energy's Form 10-K for Fiscal Year Ended December 31, 2018, p. 6.

65 State of New Hampshire Public Utilities Commission, Order 25,123, Docket No. DE 09-035, June 28, 2010, pp. 30-31.

66 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 2.2.

67 *Ibid.*, Section 2.3.

68 *Ibid.*, Section 4.4.

69 This portion of the 2010-2015 settlement was not included in the 2016 settlement that continued rates at 2015 levels. See "2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement", June 10, 2015, Section 13.1.

70 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 13.1.

Continued on next page

Reconciliation between Actual and Forecasts	ROE Reconciliation: every quarter the company must report its rolling 12-month average ROE for its distribution company; if the ROE exceeds 10%, 75% of the overearnings are returned to customers.[71] Other Reconciliation: on changes to the Net Distribution Plan (capital expenditures). PSNH was required to file financial documentation showing actual and forecasted changes to the net distribution utility plant.[72] If the difference between the actual change to the Net Distribution Utility Plant was less than a certain threshold, set on a year-by-year basis, then the actual net utility plant balance was compared to the forecasted. If the net utility balance was below the forecast, the revenue requirement in the next step increase was reduced by the revenue requirement associated with the difference between the forecasted and actual net distribution utility plant.[73]

71 State of New Hampshire Public Utilities Commission, Settlement Agreement, Docket No. DE-09-035, April 30, 2010, Section 4.1.

72 *Ibid.*, Section 5.2.

73 *Ibid.*, Sections 5.3-5.5.

G. Public Service Company of New Mexico

Public Service Company of New Mexico - FTY	
Term	Initial Plan: 2016-2017 (Docket: 15-00261-UT; Final Order Partially Adopting Corrected Recommended Decision) Current Plan: 2018-2019 (Docket: 16-00276-UT, Order on Notice of Acceptance)
Approval	Legislative[74]
Pilot/Transition?	No
Annual Base Rate Increases?	Increase in retail non-fuel base rate revenues to be implemented in two phases. The total increase amount is based on a non-fuel revenue requirement from a test period of January 1 through December 31, 2018. The first increase will be implemented on February 1, 2018 ("Phase I") and the second increase will occur on January 1, 2019 ("Phase II").[75]
Mandatory Stay-Out?	PSNM is not allowed to make non-fuel base rate changes with an effective date prior to Jan. 1, 2020.[76]
Mandatory Refiling?	No
Reconciliation between Actual and Forecasts	ROE Reconciliation: PSNM is required to return all earnings over the allowed ROE plus 50 bps to customers through a renewable energy rider that pre-dates the use of a future test year.[77]

74 Senate Bill 477 ("SB 477") was passed by the New Mexico legislature and became effective in June 2009 (PNM 2012 10-K, p. A-4)

75 New Mexico Public Regulation Commission, Modified Revised Stipulation, Case No. 16-00276-UT, p. 4 section A.1.

76 *Ibid.*, p. 7.

77 Public Service Company of New Mexico's Form 10-K for Fiscal Year Ended December 31, 2018, p. A-3.

H. Consolidated Edison (New York)

Consolidated Edison (New York) - MRP	
Term	Initial Plan: 1992-1995 (Docket: 91-E-0462; Order: Opinion 92-8) Current Plan: 2017-2019 (Docket: 16-E-0060)
Approval	Commission
Pilot/Transition?	No
Annual Base Rate Increases?	Includes an Attrition Relief Mechanism (ARM) based on company forecasts, which include inflation increases as well as modifications for known changes.
Mandatory Stay-Out?	The New York PSC may allow Con Ed to refile if it deems that circumstances exist that, in the judgement of the Commission, threaten the utility's economic viability or the ability to maintain safe, reliable service.[78]
Mandatory Refiling?	No; however, if the company does not file for new rates, it must make a compliance filing by December 1, 2019 to adjust the 2019 rates for 2020 (due to use of levelization in the 2016-2019 term). Required to file under the same plan type (since New York adopted a three year general rate case cycle in 1983).[79]
Reconciliation between Actual and Forecasts	ROE Reconciliation: for overearnings only. Target ROE and Deadband: 9.0%; +/- 50 bps deadband. Overearnings sharing: 9.5% ≤ ROE < 10% 50% to ratepayers; 10% ≤ ROE < 10.5% 75% to ratepayers; 10.5% ≤ ROE 90% to ratepayers Other Reconciliation: CapEx and OpEx reconciliation. For OpEx, the commission will reconcile projections for approximately 20 line-items including property taxes, contractor costs, pensions and other post-employment benefits, environmental remediation, long term debt costs, and a portion of managerial pay. For the majority of the aforementioned categories, the credits or surcharges resulting from the reconciliation will be deferred over the term of the plan and revenue requirement impacts

78 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 115.

79 Matthew Wald, "Con Ed Nears Rate Increase In 3-Year Plan," New York Times. February 11, 1992.

Continued on next page

	addressed in future rate proceedings.[80] For CapEx, the commission will reconcile based on net plant balances. If the company underinvests based on net plant balances on average across the three years, the revenue requirement will be deferred for ratepayers.[81]

80 State of New York Public Service Commission, Joint Proposal, Docket No. 16-E-0060, September 19, 2016, p. 35.

81 *Ibid.*, pp. 28-29.

I. Northern States Power (North Dakota)

Northern States Power (North Dakota) - MRP	
Term	2013-2016 (Docket: PU-12-0813; Order Adopting Settlement)
Approval	Commission
Pilot/Transition?	No
Annual Base Rate Increases?	4.9% rate increases in 2013, 2014, and 2015[82]
Mandatory Stay-Out?	May not refile prior to November 1, 2016 with the potential to seek additional revenues under a force majeure clause (impact of at least $1.5 million to the revenue requirement).[83]
Mandatory Refiling?	No
Reconciliation between Actual and Forecasts	ROE Reconciliation: allowed ROE increased over time (9.75% (2013), 10% (2014), 10%, (2015), and 10.25% (2016)).[84] NSP was required to share 50% of all overearnings with customers.

82 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, p. 5.

83 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, pp. 6-7.

84 State of North Dakota Public Service Commission, Order Adopting Settlement, Docket No. PU-12-813, February 26, 2014, Order adopting settlement p. 5.

J. Puget Sound Energy (Washington)

J. Puget Sound Energy (Washington) – MRP	
Term	2013-2016 (Docket: UE-121697; Order No. 07)
Approval	Commission
Pilot/Transition?	No
Annual Base Rate Increases?	Fixed 3% escalation of allowed revenue per year.
Mandatory Stay-Out?	Yes[85]
Mandatory Refiling?	Yes;[86] not required to be under the same plan type.
Reconciliation between Actual and Forecasts	ROE Reconciliation: all earned returns above the allowed ROE are shared 50/50 between ratepayers and the utility. Other Reconciliation: no; although PSE's decoupling plan included a reconciliation for allowed revenues per customer, this is not a reconciliation related to PSE's costs but strictly to its revenues.

[85] Washington Utilities and Transportation Commission, Order 07, Docket Nos. UE-121697 and UG-121705 (consolidated) and Docket Nos. UE-130137 and UG-130138 (consolidated), June 25, 2013, p. 4.

[86] *Ibid.*

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American Electric Power Company, Inc.

Termination of Kentucky operations sale has no immediate credit impact

On 17 April 2023, American Electric Power Company, Inc. (AEP) announced the termination of a pending transaction to sell the company's Kentucky operations to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp (not rated) for an enterprise value of $2.65 billion, including about $1.3 billion of estimated debt at closing. The failure to close the transaction will have no immediate impact on AEP's credit because of the small size of its Kentucky operations (about 4% of rate base and 2% of operating cash flow) and the anticipated replacement of the lost proceeds with cash from a pending sale of AEP's unregulated renewable portfolio.

AEP had planned to revisit its equity financing plans following closing of the Kentucky sale and of the sale of its unregulated renewable portfolio for net proceeds of about $1.2 billion. With the termination of the Kentucky transaction, however, AEP plans to maintain the equity issuances of approximately $600 million - $700 million annually currently in its financing plan. We continue to expect the company to generate a ratio of operating cash flow excluding changes in working capital (CFO pre-WC) to debt of between 13% and 15%, which we view as supportive of AEP's current Baa2 rating.

AEP's Kentucky operations include vertically integrated subsidiary Kentucky Power Company (Baa3 stable) and AEP Kentucky TransCo which is part of AEP Transmission Company, LLC (A2 stable). Kentucky Power is AEP's weakest utility subsidiary from a credit perspective, with cash flow that has historically been constrained by persistent underearning in an economically challenged service territory. The utility generated a ratio of CFO pre-WC to debt of 10.7% in 2022, up from an average of 6.9% in the prior three years, relative to the 10% CFO pre-WC to debt ratio threshold we have established for a possible downgrade. The historical financial weakness was driven by several factors including weak economic conditions, the coronavirus pandemic, severe weather, and purchased power agreement (PPA) related deferrals. While credit metrics improved in 2022, cash flow benefitted from a change in pension and postemployment benefit reserves.

In December 2022, the Kentucky Public Service Commission (KPSC) approved Kentucky Power's request to recover deferred purchased power costs associated with the utility's Rockport power plant unit power agreement (UPA). Kentucky Power was also authorized to include an allowed non-fuel, non-environmental Rockport UPA expense of $22.8 million in base rates to earn its authorized ROE in 2023 following the end of UPA in December 2022.

Kentucky Power plans to file a rate case in June 2023, with rates effective in January 2024, which we expect will also address the recovery of about $75 million of deferred storm costs.

Furthermore, Kentucky Power plans to utilize existing legislation to pursue securitization to recover retirement costs associated with its Big Sandy power plant. Assuming supportive regulatory outcomes, and considering the December 2022 expiration of the relatively high cost Rockport lease agreement and AEP's stated focus on economic development in its Kentucky service territory, we expect Kentucky Power to generate a ratio of CFO pre-WC to debt above 10% going forward. The outcome of Kentucky Power's next rate case will help inform our view of the state of AEP's regulatory relationship with the KPSC following the sale termination.

Headquartered in Columbus, Ohio, AEP is a large electric utility holding company with nine vertically integrated or retail transmission and distribution utility subsidiaries operating in eleven states. The company also operates transmission companies within the eastern and southwestern regions of the United States. AEP has a regulated rate base of around $59 billion and serves about 5.6 million customers.

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Issuer Ranking:

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest

January 10, 2023

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The following list ranks North American regulated utility companies that S&P Global Ratings rates based on rating and outlook. Companies with the same rating and outlook are listed in alphabetic order. We've provided the stand-alone credit profile, business risk profile, and financial risk profile of each company for informational purposes only. We have also listed the primary analyst for each company.

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Alberta Electric System Operator (AESO)	AA-	Stable	aa-	Excellent	Modest	De Juliis, David S
Madison Gas & Electric Co.	AA-	Stable	aa-	Excellent	Intermediate	Rony, Shiny A
Midcontinent Independent System Operator Inc.	AA-	Stable	aa-	Excellent	Modest	Babitsch, Daria
California Independent System Operator Corp.	A+	Positive	a+	Excellent	Intermediate	Babitsch, Daria
American Transmission Co.	A+	Stable	a+	Excellent	Intermediate	Gantt, Beverly R
California Water Service Co.	A+	Stable	a+	Excellent	Intermediate	Gantt, Beverly R
Northwest Natural Gas Co.	A+	Stable	a+	Excellent	Intermediate	Deval, Mayur
American States Water Co.	A+	Negative	a+	Excellent	Intermediate	De Juliis, David S
Golden State Water Co.	A+	Negative	aa-	Excellent	Intermediate	De Juliis, David S
Connecticut Light & Power Co.	A	Positive	a	Excellent	Intermediate	Millman, CFA, FRM, Sloan
NSTAR Electric Co.	A	Positive	a+	Excellent	Intermediate	Millman, CFA, FRM, Sloan
Toronto Hydro Corp.	A	Positive	a	Excellent	Intermediate	El Gamal, Omar

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
AltaLink Investments L.P.	A	Stable	bbb+	Excellent	Significant	Agrawal, Ruchi
AltaLink L.P.	A	Stable	a-	Excellent	Significant	Agrawal, Ruchi
American Water Works Co. Inc.	A	Stable	a	Excellent	Significant	Hernandez, William
Aqua Pennsylvania Inc.	A	Stable	a+	Excellent	Intermediate	Gantt, Beverly R
Baltimore Gas & Electric Co.	A	Stable	a	Excellent	Intermediate	Babitsch, Daria
Berkshire Hathaway Energy Co.	A	Stable	bbb	Excellent	Significant	Millman, CFA, FRM, Sloan
Central Maine Power Co.	A	Stable	a	Excellent	Significant	El Gamal, Omar
Energir Inc.	A	Stable	a	Excellent	Intermediate	El Gamal, Omar
Entegrus Powerlines Inc.	A	Stable	a	Excellent	Intermediate	Deval, Mayur
Essential Utilities Inc.	A	Stable	a	Excellent	Significant	Gantt, Beverly R
Florida Power & Light Co.	A	Stable	a+	Excellent	Intermediate	Babitsch, Daria
GrandBridge Energy Inc.	A	Stable	a	Excellent	Intermediate	Deval, Mayur
Green Mountain Power Corp.	A	Stable	bbb+	Excellent	Significant	El Gamal, Omar
London Hydro Inc.	A	Stable	a	Excellent	Intermediate	De Juliis, David S
MidAmerican Energy Co.	A	Stable	a-	Excellent	Significant	De Juliis, David S
Middlesex Water Co.	A	Stable	a	Excellent	Intermediate	Babitsch, Daria
Nevada Power Co.	A	Stable	bbb	Strong	Significant	De Juliis, David S
New Jersey-American Water Co.	A	Stable	a+	Excellent	Intermediate	Hernandez, William
Oncor Electric Delivery Co. LLC	A	Stable	a	Excellent	Intermediate	Babitsch, Daria
PacifiCorp	A	Stable	bbb+	Excellent	Significant	De Juliis, David S
Pennsylvania-American Water Co.	A	Stable	a+	Excellent	Intermediate	Hernandez, William
PNG Cos. LLC	A	Stable	a-	Excellent	Significant	Gantt, Beverly R

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
PPL Electric Utilities Corp.	A	Stable	a	Excellent	Significant	O'Neill, Matthew L
Public Service Co. of New Hampshire	A	Stable	a	Excellent	Intermediate	Millman, CFA, FRM, Sloan
San Jose Water Co.	A	Stable	a	Excellent	Intermediate	Gantt, Beverly R
Sierra Pacific Power Co.	A	Stable	bbb	Strong	Significant	Millman, CFA, FRM, Sloan
Veolia Utility Resources LLC	A	Stable	a	Excellent	Intermediate	De Juliis, David S
Windsor Canada Utilities Ltd.	A	Stable	a	Excellent	Intermediate	De Juliis, David S
Wisconsin Gas LLC	A	Stable	a	Excellent	Intermediate	Rony, Shiny A
Evergy Metro Inc.	A	Negative	a	Excellent	Significant	Rony, Shiny A
Southern California Gas Co.	A	Negative	a	Excellent	Significant	De Juliis, David S
Wisconsin Power & Light Co.	A	Negative	a	Excellent	Significant	Gantt, Beverly R
Aquarion Co.	A-	Positive	bbb	Excellent	Aggressive	De Juliis, David S
Eversource Energy	A-	Positive	a-	Excellent	Significant	Millman, CFA, FRM, Sloan
Eversource Gas Co. of Massachusetts	A-	Positive	bbb	Strong	Significant	De Juliis, David S
NSTAR Gas Co.	A-	Positive	a-	Excellent	Significant	De Juliis, David S
Yankee Gas Services Co.	A-	Positive	bbb+	Excellent	Significant	De Juliis, David S
AEP Texas Inc.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
AEP Transmission Co. LLC	A-	Stable	a+	Excellent	Intermediate	Babitsch, Daria
Alabama Power Co.	A-	Stable	a	Excellent	Intermediate	Rony, Shiny A
Alectra Inc.	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
Alliant Energy Corp.	A-	Stable	a-	Excellent	Significant	Gantt, Beverly R
American Electric Power Co. Inc.	A-	Stable	a-	Excellent	Significant	Grosberg, Gabe
Appalachian Power Co.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Atlantic City Electric Co.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
Atmos Energy Corp.	A-	Stable	a-	Excellent	Significant	Rony, Shiny A
Berkshire Gas Co.	A-	Stable	a-	Strong	Intermediate	El Gamal, Omar
Connecticut Natural Gas Corp.	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
Connecticut Water Service Inc.	A-	Stable	a-	Excellent	Intermediate	Gantt, Beverly R
Consolidated Edison Co. of New York Inc.	A-	Stable	a-	Excellent	Significant	O'Neill, Matthew L
Consolidated Edison Inc.	A-	Stable	a-	Excellent	Significant	O'Neill, Matthew L
Consumers Energy Co.	A-	Stable	a-	Excellent	Significant	Agrawal, Ruchi
CU Inc.	A-	Stable	a	Excellent	Intermediate	Deval, Mayur
Delmarva Power & Light Co.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
DTE Electric Co.	A-	Stable	a-	Excellent	Significant	Ugboaja, Obioma
DTE Gas Co.	A-	Stable	a+	Excellent	Intermediate	Agrawal, Ruchi
Enbridge Gas Inc.	A-	Stable	a-	Excellent	Significant	De Juliis, David S
Entergy Arkansas, LLC	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
Entergy Mississippi, LLC	A-	Stable	a	Excellent	Significant	El Gamal, Omar
EPCOR Utilities Inc.	A-	Stable	a-	Excellent	Significant	Agrawal, Ruchi
Fortis Inc.	A-	Stable	a-	Excellent	Significant	Deval, Mayur
FortisAlberta Inc.	A-	Stable	a-	Excellent	Significant	Deval, Mayur
Hydro One Inc.	A-	Stable	a-	Excellent	Significant	Deval, Mayur
Hydro One Ltd.	A-	Stable	a-	Excellent	Significant	Deval, Mayur
Indiana Michigan Power Co.	A-	Stable	a-	Excellent	Intermediate	Babitsch, Daria
Integrys Holding Inc.	A-	Stable	a-	Excellent	Significant	Rony, Shiny A
Interstate Power & Light Co.	A-	Stable	a-	Excellent	Significant	Gantt, Beverly R
ITC Holdings Corp.	A-	Stable	a-	Excellent	Significant	Deval, Mayur

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Kentucky Utilities Co.	A-	Stable	a-	Excellent	Significant	Gantt, Beverly R
Louisville Gas & Electric Co.	A-	Stable	a-	Excellent	Significant	Gantt, Beverly R
Narragansett Electric Co.	A-	Stable	bbb+	Excellent	Significant	O'Neill, Matthew L
New York State Electric & Gas Corp.	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
NextEra Energy Inc.	A-	Stable	a-	Excellent	Significant	Jepsen, CFA, Gerrit W
Nicor Gas Co.	A-	Stable	a	Excellent	Significant	Rony, Shiny A
Northern States Power Co.	A-	Stable	a	Excellent	Significant	Hernandez, William
Northern States Power Wisconsin	A-	Stable	a-	Excellent	Intermediate	Hernandez, William
Ohio Power Co.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
Oklahoma Gas & Electric Co.	A-	Stable	a-	Excellent	Significant	Millman, CFA, FRM, Sloan
ONE Gas Inc.	A-	Stable	a-	Excellent	Significant	De Juliis, David S
Orange and Rockland Utilities Inc.	A-	Stable	bbb+	Excellent	Significant	O'Neill, Matthew L
Peoples Gas Light & Coke Co. (The)	A-	Stable	a-	Excellent	Significant	Rony, Shiny A
Pepco Holdings LLC	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
Potomac Electric Power Co.	A-	Stable	a-	Excellent	Significant	Babitsch, Daria
PPL Corp.	A-	Stable	a-	Excellent	Significant	O'Neill, Matthew L
Public Service Co. of Colorado	A-	Stable	a-	Excellent	Significant	Hernandez, William
Public Service Co. of Oklahoma	A-	Stable	bbb	Strong	Significant	Babitsch, Daria
Public Service Electric & Gas Co.	A-	Stable	a+	Excellent	Intermediate	Jepsen, CFA, Gerrit W
Rochester Gas & Electric Corp.	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
SJW Group	A-	Stable	a-	Excellent	Significant	Gantt, Beverly R
Southern Connecticut Gas Co.	A-	Stable	a-	Excellent	Significant	El Gamal, Omar

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Southwestern Electric Power Co.	A-	Stable	bbb+	Excellent	Significant	Babitsch, Daria
Southwestern Public Service Co.	A-	Stable	bbb+	Excellent	Significant	Hernandez, William
Spire Alabama Inc.	A-	Stable	a+	Excellent	Intermediate	Hernandez, William
Spire Inc.	A-	Stable	a-	Excellent	Significant	Hernandez, William
Spire Missouri Inc.	A-	Stable	a+	Excellent	Intermediate	Hernandez, William
Tucson Electric Power Co.	A-	Stable	bbb+	Excellent	Significant	Deval, Mayur
United Illuminating Co. (The)	A-	Stable	a-	Excellent	Significant	El Gamal, Omar
Washington Gas Light Co.	A-	Stable	a-	Excellent	Significant	Agrawal, Ruchi
WEC Energy Group Inc.	A-	Stable	a-	Excellent	Significant	Hernandez, William
Wisconsin Electric Power Co.	A-	Stable	a-	Excellent	Significant	Rony, Shiny A
Wisconsin Public Service Corp.	A-	Stable	a-	Excellent	Significant	Rony, Shiny A
Xcel Energy Inc.	A-	Stable	a-	Excellent	Significant	Hernandez, William
York Water Co. (The)	A-	Stable	a-	Excellent	Intermediate	Babitsch, Daria
Evergy Kansas Central Inc.	A-	Negative	a-	Excellent	Significant	Rony, Shiny A
Evergy Kansas South Inc.	A-	Negative	aa-	Excellent	Modest	Rony, Shiny A
Evergy Missouri West Inc.	A-	Negative	bbb	Strong	Significant	Rony, Shiny A
Evergy Inc.	A-	Negative	a-	Excellent	Significant	Rony, Shiny A
Commonwealth Edison Co.	BBB+	Positive	bbb+	Excellent	Significant	Babitsch, Daria
Exelon Corp.	BBB+	Positive	bbb+	Excellent	Significant	Jepsen, CFA, Gerrit W
PECO Energy Co.	BBB+	Positive	a	Excellent	Intermediate	Babitsch, Daria
Texas-New Mexico Power Co.	BBB+	Positive	a-	Excellent	Significant	El Gamal, Omar
Ameren Corp.	BBB+	Stable	bbb+	Excellent	Significant	Hernandez, William
Ameren Illinois Co.	BBB+	Stable	a-	Excellent	Significant	Hernandez, William

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
ATCO Ltd.	BBB+	Stable	bbb+	Excellent	Significant	Deval, Mayur
Atlanta Gas Light Co.	BBB+	Stable	aa-	Excellent	Intermediate	Rony, Shiny A
AVANGRID Inc.	BBB+	Stable	bbb+	Strong	Significant	El Gamal, Omar
Black Hills Corp.	BBB+	Stable	bbb+	Excellent	Significant	Rony, Shiny A
Black Hills Power Inc.	BBB+	Stable	a-	Excellent	Significant	Rony, Shiny A
Boston Gas Co.	BBB+	Stable	bbb+	Strong	Significant	Agrawal, Ruchi
Brooklyn Union Gas Co. (The)	BBB+	Stable	bbb	Strong	Significant	De Juliis, David S
Canadian Utilities Ltd.	BBB+	Stable	bbb+	Excellent	Aggressive	Deval, Mayur
Caribbean Utilities Co. Ltd.	BBB+	Stable	bbb+	Strong	Significant	Deval, Mayur
CenterPoint Energy Houston Electric LLC	BBB+	Stable	a	Excellent	Significant	Hernandez, William
CenterPoint Energy Inc.	BBB+	Stable	bbb+	Excellent	Significant	Hernandez, William
CenterPoint Energy Resources Corp.	BBB+	Stable	a-	Excellent	Significant	Hernandez, William
Central Hudson Gas & Electric Corp.	BBB+	Stable	bbb+	Excellent	Significant	Deval, Mayur
Cleco Power LLC	BBB+	Stable	a-	Excellent	Significant	Rony, Shiny A
CMS Energy Corp.	BBB+	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Dominion Energy South Carolina Inc.	BBB+	Stable	bbb	Strong	Significant	Millman, CFA, FRM, Sloan
Dominion Energy Inc.	BBB+	Stable	bbb+	Excellent	Significant	Ugboaja, Obioma
DTE Energy Co.	BBB+	Stable	bbb+	Excellent	Significant	Ugboaja, Obioma
Duke Energy Carolinas LLC	BBB+	Stable	a-	Excellent	Significant	Gantt, Beverly R
Duke Energy Corp.	BBB+	Stable	bbb+	Excellent	Significant	O'Neill, Matthew L
Duke Energy Florida LLC	BBB+	Stable	a-	Excellent	Significant	Gantt, Beverly R
Duke Energy Indiana Inc.	BBB+	Stable	a-	Excellent	Significant	Gantt, Beverly R
Duke Energy Kentucky Inc.	BBB+	Stable	bbb+	Excellent	Significant	Gantt, Beverly R
Duke Energy Ohio Inc.	BBB+	Stable	a-	Excellent	Significant	Gantt, Beverly R

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Duke Energy Progress LLC	BBB+	Stable	a-	Excellent	Significant	Gantt, Beverly R
Duquesne Light Co.	BBB+	Stable	aa-	Excellent	Modest	De Juliis, David S
Entergy Corp.	BBB+	Stable	bbb+	Excellent	Significant	O'Neill, Matthew L
Entergy Louisiana LLC	BBB+	Stable	bbb+	Excellent	Significant	El Gamal, Omar
Entergy Texas Inc.	BBB+	Stable	bbb+	Excellent	Aggressive	El Gamal, Omar
Georgia Power Co.	BBB+	Stable	bbb+	Excellent	Significant	Rony, Shiny A
Indiana Gas Co. Inc.	BBB+	Stable	a+	Excellent	Intermediate	Rony, Shiny A
KeySpan Gas East Corp.	BBB+	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Maritime Electric Co. Ltd.	BBB+	Stable	bbb+	Strong	Significant	Deval, Mayur
Massachusetts Electric Co.	BBB+	Stable	a-	Excellent	Significant	Agrawal, Ruchi
Mississippi Power Co.	BBB+	Stable	bbb+	Strong	Significant	Rony, Shiny A
National Grid North America Inc.	BBB+	Stable	bbb+	Excellent	Aggressive	Millman, CFA, FRM, Sloan
New England Power Co.	BBB+	Stable	aa-	Excellent	Modest	Agrawal, Ruchi
Niagara Mohawk Power Corp.	BBB+	Stable	a-	Excellent	Significant	Millman, CFA, FRM, Sloan
NiSource Inc.	BBB+	Stable	bbb+	Excellent	Significant	Gantt, Beverly R
Northern Indiana Public Service Co. LLC	BBB+	Stable	a-	Excellent	Intermediate	Gantt, Beverly R
OGE Energy Corp.	BBB+	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Ontario Power Generation Inc.	BBB+	Stable	bb+	Strong	Significant	Deval, Mayur
Otter Tail Power Co.	BBB+	Stable	bbb+	Strong	Significant	Agrawal, Ruchi
Piedmont Natural Gas Co. Inc.	BBB+	Stable	a	Excellent	Intermediate	Gantt, Beverly R
Portland General Electric Co.	BBB+	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Progress Energy Inc.	BBB+	Stable	bbb+	Excellent	Significant	Gantt, Beverly R
Public Service Co. of North Carolina Inc.	BBB+	Stable	a	Excellent	Intermediate	De Juliis, David S

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Public Service Enterprise Group Inc.	BBB+	Stable	bbb+	Excellent	Significant	Jepsen, CFA, Gerrit W
Questar Gas Co.	BBB+	Stable	a-	Excellent	Significant	De Juliis, David S
San Diego Gas & Electric Co.	BBB+	Stable	bbb+	Excellent	Significant	Ugboaja, Obioma
Southern Co.	BBB+	Stable	bbb+	Excellent	Significant	Grosberg, Gabe
Southern Co. Gas	BBB+	Stable	bbb+	Strong	Significant	Rony, Shiny A
Southern Indiana Gas & Electric Co.	BBB+	Stable	a	Excellent	Significant	Hernandez, William
System Energy Resources Inc.	BBB+	Stable	bbb	Strong	Intermediate	El Gamal, Omar
The East Ohio Gas Co. d/b/a Dominion Energy Ohio	BBB+	Stable	a-	Excellent	Significant	De Juliis, David S
Union Electric Co. d/b/a Ameren Missouri	BBB+	Stable	bbb+	Excellent	Significant	Hernandez, William
Unitil Corp.	BBB+	Stable	bbb+	Excellent	Significant	Rony, Shiny A
Vectren Utility Holdings LLC	BBB+	Stable	a-	Excellent	Significant	Hernandez, William
Virginia Electric & Power Co.	BBB+	Stable	a	Excellent	Significant	Ugboaja, Obioma
Cascade Natural Gas Corp.	BBB+	Developing	bbb	Strong	Significant	Hernandez, William
MDU Resources Group Inc.	BBB+	Developing	bbb+	Satisfactory	Significant	Hernandez, William
Montana-Dakota Utilities Co.	BBB+	Developing	bbb+	Excellent	Significant	Hernandez, William
Kentucky Power Co.	BBB+	WatchNeg	bbb	Strong	Significant	Babitsch, Daria
Arizona Public Service Co.	BBB+	Negative	bbb+	Excellent	Significant	Gantt, Beverly R
Pinnacle West Capital Corp.	BBB+	Negative	bbb+	Excellent	Significant	Gantt, Beverly R
Sempra Energy	BBB+	Negative	bbb+	Strong	Significant	Ugboaja, Obioma
Tampa Electric Co.	BBB+	Negative	a	Excellent	Significant	Deval, Mayur
Versant Power	BBB+	Negative	bbb+	Strong	Significant	Agrawal, Ruchi
Indianapolis Power & Light Co.	BBB	Positive	a-	Excellent	Significant	El Gamal, Omar

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
IPALCO Enterprises Inc.	BBB	Positive	bbb	Excellent	Aggressive	El Gamal, Omar
PNM Resources Inc.	BBB	Positive	bbb	Strong	Significant	El Gamal, Omar
Public Service Co. of New Mexico	BBB	Positive	bbb	Strong	Significant	El Gamal, Omar
Southwest Gas Corp.	BBB	Positive	a-	Excellent	Significant	O'Neill, Matthew L
ALLETE Inc.	BBB	Stable	bbb	Strong	Significant	Hernandez, William
American Transmission Systems Inc.	BBB	Stable	a	Excellent	Intermediate	Millman, CFA, FRM, Sloan
Cleveland Electric Illuminating Co.	BBB	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Duquesne Light Holdings Inc.	BBB	Stable	bbb	Excellent	Aggressive	De Juliis, David S
Edison International	BBB	Stable	bbb	Strong	Significant	Ugboaja, Obioma
Hawaiian Electric Co. Inc.	BBB	Stable	bbb	Strong	Significant	Agrawal, Ruchi
IDACORP Inc.	BBB	Stable	bbb	Strong	Significant	Gantt, Beverly R
Idaho Power Co.	BBB	Stable	bbb	Strong	Significant	Gantt, Beverly R
Jersey Central Power & Light Co.	BBB	Stable	bbb	Strong	Significant	De Juliis, David S
Metropolitan Edison Co.	BBB	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Mid-Atlantic Interstate Transmission LLC	BBB	Stable	a	Excellent	Intermediate	Millman, CFA, FRM, Sloan
Monongahela Power Co.	BBB	Stable	bbb	Strong	Significant	Millman, CFA, FRM, Sloan
National Grid Generation LLC	BBB	Stable	bbb-	Fair	Intermediate	Millman, CFA, FRM, Sloan
NorthWestern Corp.	BBB	Stable	bbb	Strong	Significant	Deval, Mayur
Ohio Edison Co.	BBB	Stable	a+	Excellent	Modest	Agrawal, Ruchi
Otter Tail Corp.	BBB	Stable	bbb	Satisfactory	Intermediate	Agrawal, Ruchi
Pennsylvania Electric Co.	BBB	Stable	bbb+	Excellent	Significant	Agrawal, Ruchi
Pennsylvania Power Co.	BBB	Stable	a	Excellent	Intermediate	Agrawal, Ruchi

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Potomac Edison Co.	BBB	Stable	bbb	Strong	Significant	Millman, CFA, FRM, Sloan
Puget Sound Energy Inc.	BBB	Stable	bbb+	Excellent	Significant	Hernandez, William
SEMCO Energy Inc.	BBB	Stable	a-	Excellent	Significant	Agrawal, Ruchi
Southern California Edison Co.	BBB	Stable	bbb	Strong	Significant	Ugboaja, Obioma
Southern Power Co.	BBB	Stable	bb+	Satisfactory	Significant	Rony, Shiny A
Toledo Edison Co.	BBB	Stable	bbb+	Excellent	Significant	Millman, CFA, FRM, Sloan
Trans-Allegheny Interstate Line Co.	BBB	Stable	aa-	Excellent	Modest	Agrawal, Ruchi
West Penn Power Co.	BBB	Stable	a-	Excellent	Intermediate	De Juliis, David S
Elizabethtown Gas Co.	BBB	WatchNeg	a-	Excellent	Significant	Agrawal, Ruchi
South Jersey Gas Co.	BBB	WatchNeg	a-	Excellent	Significant	Ugboaja, Obioma
South Jersey Industries Inc.	BBB	WatchNeg	bbb	Excellent	Aggressive	Ugboaja, Obioma
Algonquin Power & Utilities Corp.	BBB	Negative	bbb	Strong	Significant	El Gamal, Omar
Avista Corp.	BBB	Negative	bbb	Strong	Significant	Agrawal, Ruchi
Emera Inc.	BBB	Negative	bbb	Excellent	Aggressive	Deval, Mayur
Empire District Electric Co.	BBB	Negative	bbb	Strong	Significant	El Gamal, Omar
Southwest Gas Holdings Inc.	BBB-	Positive	bbb-	Satisfactory	Significant	O'Neill, Matthew L
MountainWest Pipeline LLC	BBB-	WatchPos	bbb-	Satisfactory	Intermediate	O'Neill, Matthew L
AltaGas Ltd.	BBB-	Stable	bbb-	Strong	Aggressive	Agrawal, Ruchi
Cleco Corporate Holdings LLC	BBB-	Stable	bbb	Satisfactory	Significant	Rony, Shiny A
FirstEnergy Corp.	BBB-	Stable	bbb-	Excellent	Aggressive	Millman, CFA, FRM, Sloan
FirstEnergy Transmission LLC	BBB-	Stable	a-	Excellent	Intermediate	De Juliis, David S
Fortis TCI Ltd.	BBB-	Stable	bb+	Satisfactory	Significant	Deval, Mayur

North American Electric, Gas, And Water Regulated Utilities--Strongest To Weakest (cont.)

North American regulated utility	Current rating	Current outlook or CreditWatch	Stand-alone credit profile	Business risk profile	Financial risk profile	Primary analyst
Hawaiian Electric Industries Inc.	BBB-	Stable	bbb-	Strong	Significant	Agrawal, Ruchi
Puget Energy Inc.	BBB-	Stable	bbb+	Excellent	Significant	Hernandez, William
WGL Holdings Inc.	BBB-	Stable	a-	Excellent	Significant	Agrawal, Ruchi
ENMAX Corp.	BBB-	Negative	bbb-	Strong	Aggressive	Agrawal, Ruchi
Nova Scotia Power Inc.	BBB-	Negative	bb+	Strong	Aggressive	Deval, Mayur
Entergy New Orleans LLC	BB	Developing	bb	Satisfactory	Significant	El Gamal, Omar
Dayton Power & Light Co.	BB	Negative	bbb-	Strong	Significant	Millman, CFA, FRM, Sloan
DPL Inc.	BB	Negative	bb-	Strong	Highly Leveraged	Millman, CFA, FRM, Sloan
Pacific Gas & Electric Co.	BB-	Stable	bb-	Satisfactory	Significant	Babitsch, Daria
PG&E Corp.	BB-	Stable	bb-	Satisfactory	Significant	Jepsen, CFA, Gerrit W
Centuri Group Inc.	B+	Developing	b+	Weak	Aggressive	O'Neill, Matthew L

Ratings as of Jan. 3, 2023.

This report does not constitute a rating action.

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North American Utilities, Power & Gas Outlook 2023

Cost Pressures Challenge the Status Quo

Fitch's Sector Outlook: Deteriorating

Fitch Ratings' Deteriorating Outlook for the North American Utilities, Power & Gas sector reflects mounting costs pressures for electric and gas utilities due to elevated commodity prices, inflationary headwinds and rising interest costs. High capex and recovery of storm restoration costs from more frequent extreme weather activity are compounding cost pressures, leading to significant increases in customer bills. Deferred fuel balances are on the rise, weighing on the balance sheets of many integrated utilities and parent holding companies.

Resilient retail electricity sales, potential for higher authorized ROEs and use of tools such as securitization of under-recovered fuel balances could provide some offset to utilities in managing the headwinds. Ongoing management actions to monetize parts of businesses at attractive valuations is driving an improved business mix for the sector and, in some cases, leading to deleveraging.

Rating Outlook Distribution

Within Fitch's coverage, 88% of ratings hold Stable Outlooks. We expect limited rating movement in 2023. The number of upgrades in 2022 so far exceeds the number of downgrades and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.

Examples are Consolidated Edison, Inc. (BBB+/Stable), Edison International (BBB−/Positive), FirstEnergy Corp. (BBB−/Stable), Hawaiian Electric Industries, Inc. (BBB/Positive) and PG&E Corporation (BB/Positive). Unforeseen deterioration in state regulation and higher than anticipated leverage remains a rating risk, especially if natural gas prices rise again from current levels.

The median senior unsecured rating for operating subsidiaries remains steadfast in 2022 at 'A−' and we expect no change in 2023. The median senior unsecured rating for parent holding companies is currently 'BBB'. We expect this median to hold in 2023, despite Negative Rating Outlooks on several parent holding companies, such as AVANGRID, Inc. (BBB+), DPL Inc. (BB), Emera Incorporated (BBB), Pinnacle West Capital Corporation (BBB+), The Southern Company (BBB+) and Vistra Corp. (BB+).

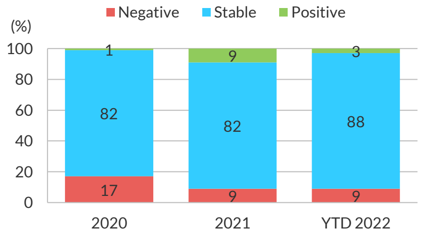
What to Watch

- Effects of bill affordability on the regulatory construct.
- Rising levels and higher volatility in natural gas prices.
- Higher capex.

Shalini Mahajan, Managing Director

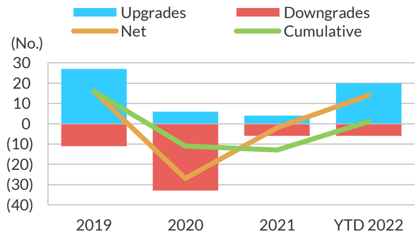
"Fitch expects utility bill affordability to remain a front and center issue for the industry, as higher natural gas prices and rising operating and financing costs continue to put pressure on customer bills. Despite modest improvement, we forecast FFO leverage for the sector to remain elevated, due to high capex and an extended recovery of large deferred fuel balances."

North American Utilities, Power & Gas — Rating Outlooks



Source: Fitch Ratings.

North American Utilities, Power & Gas — Rating Changes



Source: Fitch Ratings.

North American Utilities, Power and Gas — Median Credit Metrics

	2021	2022F	2023F	2024F
Revenue Growth (%)	11.0	2.0	2.5	3.5
FFO Margin (%)	24.0	27.0	30.0	31.0
FFO Leverage (x)	6.0	5.7	5.3	5.2
FFO Interest Coverage (x)	4.6	4.5	4.6	4.5

F — Forecast.
Source: Fitch Ratings. Fitch Solutions.

What to Watch

Core Assumption

The key economic assumptions underlying our sector and Ratings Outlooks include a mild recession in 2023, CPI inflation of 3.60% and a 10-year U.S. Treasury rate of 3.75% at YE 2023. We use Fitch's natural gas price assumption for Henry Hub of $5.00/per million British thermal units (mmBtu). Other key assumptions include flat retail electricity sales in 2023 and elevated capex across the industry.

What to Watch — Bill Affordability

Higher natural gas prices are driving utility bills higher, coinciding with higher operating costs due to inflationary pressures and rising financing costs. The average residential price of electricity in the U.S. increased 14% yoy, as of August 2022, based upon data from the U.S. Energy Information Administration (EIA). Following a 4% increase in 2021, this marks a sharp reversal of fairly muted increases in residential electricity prices in the last two decades.

What to Watch — High Natural Gas Prices

Higher natural gas prices are driving a significant increase in the electricity component of CPI in 2022. The 12-month change in the Electricity Price Index was 14.1% in October 2022, following a 15.5% change in September 2022. With natural gas comprising 40% of the total electricity generation mix in the U.S. and linkages with global natural gas markets increasing, higher and more volatile natural gas prices are likely to become the norm.

What to Watch — Higher Capex

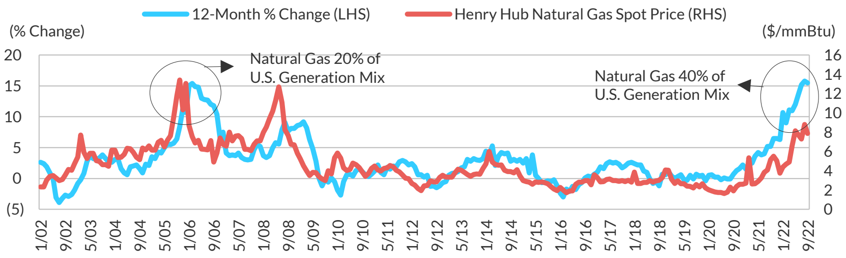
Utilities continue to invest in storm-hardening, grid modernization and renewable generation among other capex. Based on data from Edison Electrical Institute (EEI), industry capex is projected to increase 15% in 2022. Fitch believes EEI projections for 2023 and 2024 are likely to be revised higher as many utilities continue to target 7%–9% rate base growth.

Along with higher capex, a sharp increase in interest rates does not bode well for this capital-intensive sector. This is occurring as inflationary pressures and supply chain challenges are likely to materially increase O&M costs, reversing the historical trend. In the last decade O&M costs for integrated utilities have declined, while those for transmission and distribution utilities grew in line with inflation.

Additional Key Sector Issues

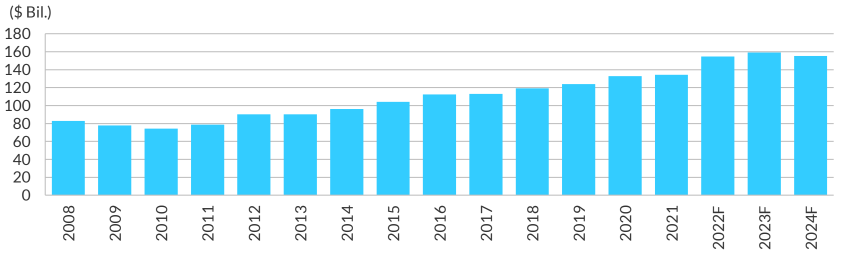
- Retail sales trends.
- Potential for higher ROEs.
- Portfolio management actions.
- Tailwinds from the Inflation Reduction Act.
- Weakened leverage metrics.

Electricity Price Index Vs. Natural Gas Prices



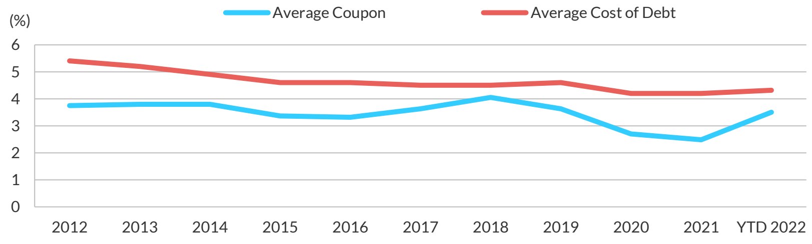
MmBtu – Million British thermal units.
Source: Fitch Ratings.

Total Capex of U.S. Investor-Owned Electric Utilities



F – Forecast.
Source: Fitch Ratings.

Sector Interest Rates



Source: Fitch Ratings.

Key Sector Issues

Retail Sales Trend

Retail sales continue to show resilience and increased 3.0% yoy through 3Q22 according to data from the U.S. EIA. Residential sales increased 3.1%, in part driven by favorable weather, and remain above pre-pandemic levels from persistent hybrid work trends. Commercial sales increased 4.0%, while industrial sales increased 1.7%. Fitch expects total retail sales to be flat in 2023 versus 2022 levels, due to higher margin residential sales remaining resilient in the face of a potential mild recession.

Potential for Higher ROEs

Given a historic spread between median authorized ROEs and 10-year U.S. treasury rates of 600bps to 700bps, Fitch expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag. Favorably, the gap between authorized and earned ROEs continues to narrow, reflecting a better regulatory construct in most jurisdictions.

Portfolio Management Actions

Companies continue to simplify business mix, while at the same time capitalizing on higher valuations of non-regulated renewable businesses. Partial or full sales of regulated subsidiaries continues to be an attractive option for companies, compared with issuing equity, given robust demand from infrastructure investors and financial sponsors. In most cases, these transactions are neutral to positive for credit.

Tailwinds from the Inflation Reduction Act

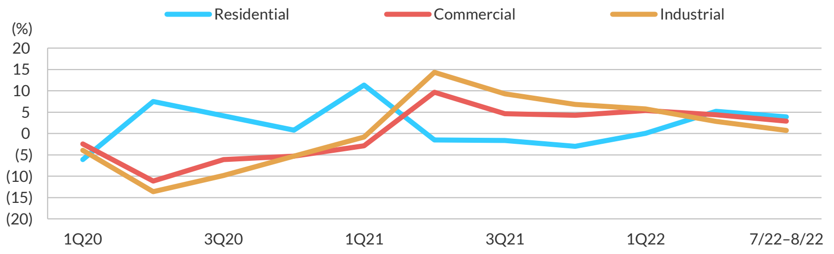
Fitch views the Inflation Reduction Act to be positive for the industry, since the attractive tax incentives for clean generation will offset the inflationary bill pressures and lower the cost of energy transition to customers. Transferability of tax credits provides utilities and power generation companies enhanced financial flexibility to fund clean investments. Integrated utilities benefit the most and Fitch expects them to accelerate the replacement of fossil generation with renewables.

Weakened Leverage Metrics

Median leverage metrics for the sector are expected to worsen in 2022, driven by significant deferred fuel balances as utilities try to spread the recovery of these costs over an extended period of time in order to manage bill effects for customers. Median FFO leverage for the operating subsidiaries is expected to be approximately 4.9x in 2022 and we expect this ratio to improve as utilities recover deferred fuel balances in the next 12–24 months.

Median FFO leverage for parent holding companies continues to be elevated and we expect managements to continue to look for asset monetization opportunities to supplement or replace equity needs. Higher than expected natural gas prices remain the largest risk. More increases in deferred fuel balances will shrink the ability for utilities to seek timely recovery of capex. The sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector.

Yoy Change in Retail Electricity Sales



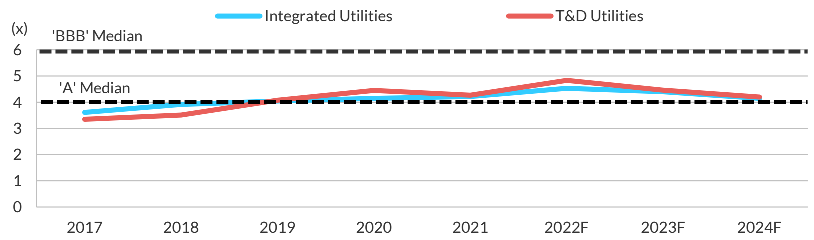
Source: Fitch Ratings.

Announced Portfolio Management Transactions

Seller	Asset	Purchaser	Amount
American Electric Power	Kentucky Power, AEP Kentucky Transmission	Algonquin Power & Utilities Corp.	$2.646 billion enterprise value. $1.220 billion assumed debt.
Centerpoint Energy Inc.	Arkansas and Oklahoma LDCs	Summit Utilities	$2.15 billion.
Consolidated Edison, Inc.	Con Edison Clean Energy Businesses, Inc.	RWE Renewables Americas, LLC	$6.80 billion enterprise value. $2.70 billion assumed debt.
Duke Energy Corp.	Duke Energy Indiana — 19.9% stake	GIC Private Limited	$2.05 billion.
Firstenergy Corp.	FirstEnergy Transmission LLC — 19.9% State	Brookfield Infrastructure Partners	$2.375 billion.
Public Service Enterprise Group, Inc.	Fossil Generation Assets	ArcLight Capital	$1.90 billion.
Sempra Energy	Sempra Infrastructure Partners	KKR & Co. Inc. (20%), ADIA (10%)	KKR & Co. Inc. — $3.20 billion ADIA — $1.80 billion

LDC – Local distribution company. ADIA – Abu Dhabi Investment Authority.
Source: Fitch Ratings, Fitch Solutions.

Trend in Median FFO Leverage for Operating Companies



T&D – Transmission and distribution. F – Forecast.
Source: Fitch Ratings.

Appendix:

North American Utilities, Power & Gas Sector

			Net Revenue Growth (%)			FFO Margin (%)			FFO Leverage (x)			FFO Interest Coverage (x)			
Issuer	IDR	Outlook	2022F	2023F	2024F	2022F	2023F	2024F	2022F	2023F	2024F	2022F	2023F	2024F	RAC Link
American Electric Power Company, Inc.	BBB	Stable	1.0	2.0	5.0	33.0	33.0	34.0	5.8	5.6	5.6	4.2	4.1	4.1	October 2022
AVANGRID, Inc.	BBB+	Negative	22.0	3.0	8.0	25.0	25.0	27.0	6.7	5.2	5.1	3.6	4.0	4.8	October 2022
Black Hills Corporation	BBB+	Stable	26.0	0.0	(3.0)	31.0	30.0	30.0	4.7	4.7	5.0	5.0	5.0	4.4	October 2022
CenterPoint Energy, Inc.	BBB	Stable	(5.0)	1.0	5.0	19.0	34.0	35.0	8.0	5.4	5.4	2.8	4.7	4.7	March 2022
Cleco Corporate Holdings LLC	BBB–	Stable	14.0	4.0	7.0	25.0	22.0	18.0	5.6	5.5	5.4	4.8	4.4	4.0	March 2022
CMS Energy Corporation	BBB	Stable	6.0	4.0	5.0	26.0	26.0	26.0	5.4	5.1	5.2	2.7	2.4	2.3	October 2022
DPL Inc.	BB	Negative	4.0	11.0	5.0	16.0	21.0	22.0	9.3	7.4	7.2	1.7	2.5	2.5	April 2022
DTE Energy Company	BBB	Stable	(5.0)	4.0	3.0	19.0	21.0	21.0	5.7	5.1	5.3	3.9	4.4	4.4	November 2022
Edison International	BBB–	Positive	2.0	2.0	3.0	39.0	34.0	33.0	4.6	5.1	5.2	5.4	4.5	4.3	November 2022
Eversource Energy	BBB+	Stable	4.0	5.0	8.0	29.0	31.0	30.0	5.7	5.2	5.1	5.3	5.4	5.6	June 2022
Exelon Corporation	BBB	Stable	(48.0)	1.0	5.0	26.0	29.0	32.0	6.2	6.0	5.6	3.3	3.6	3.9	September 2022
FirstEnergy Corp.	BBB–	Stable	2.0	4.0	3.0	23.0	25.0	26.0	5.9	5.7	5.6	3.3	3.7	3.7	July 2022
Hawaiian Electric Industries, Inc.	BBB	Positive	0.0	4.0	(1.0)	18.0	19.0	21.0	4.5	4.4	4.0	4.7	4.6	4.9	June 2022
IPALCO Enterprises, Inc.	BBB–	Stable	8.0	2.0	4.0	28.0	28.0	29.0	5.5	5.5	5.2	3.3	3.2	3.4	April 2022
NextEra Energy, Inc.	A–	Stable	21.0	7.0	—	52.0	52.0	—	5.0	4.5	—	6.6	6.5	—	October 2021
NiSource Inc.	BBB	Stable	10.0	3.0	5.0	29.0	31.0	36.0	6.1	6.1	5.7	4.0	3.8	4.3	June 2022
NorthWestern Corporation	BBB	Stable	(1.0)	6.0	5.0	27.0	27.0	29.0	6.5	6.4	6.1	3.8	4.0	3.9	March 2022
OGE Energy Corp.	BBB+	Stable	(32.0)	3.0	5.0	23.0	32.0	32.0	5.0	4.3	4.5	3.6	4.6	4.4	February 2022
Otter Tail Corporation	BBB–	Stable	(18.0)	(1.0)	4.0	20.0	21.0	22.0	4.1	4.2	4.2	4.7	4.5	4.5	October 2021
PG&E Corporation	BB	Positive	(5.0)	8.0	3.0	27.0	34.0	39.0	5.9	4.7	4.4	3.6	4.9	5.4	June 2022
Pinnacle West Capital Corporation	BBB+	Negative	(1.0)	1.0	3.0	32.0	29.0	31.0	5.1	5.4	5.1	3.3	2.7	2.8	October 2021
Puget Energy Inc.	BBB–	Stable	(6.0)	7.0	2.0	25.0	28.0	28.0	6.0	4.9	5.0	2.0	2.5	2.5	October 2022
Sempra Energy	BBB+	Stable	12.0	(5.0)	4.0	37.0	38.0	37.0	4.5	4.9	5.0	5.5	4.9	4.5	March 2022
The Southern Company	BBB+	Negative	11.0	(1.0)	4.0	32.0	33.0	37.0	5.6	5.3	4.7	3.8	3.8	4.4	October 2022
WEC Energy Group, Inc.	BBB+	Stable	10.0	0.0	1.0	28.0	32.0	34.0	5.9	5.2	5.1	4.1	3.5	3.2	October 2022
Xcel Energy Inc.	BBB+	Stable	(2.0)	0.0	3.0	30.0	32.0	33.0	5.2	5.0	5.0	4.5	4.7	4.6	May 2022

IDR – Issuer Default Ratings. F – Forecast.
Source: Fitch Ratings. Fitch Solutions.

Outlooks and Related Research

2023 Outlooks

Global Economic Outlook (December 2022)

U.S. Utilities: Mostly Strong Quarterly Earnings; Bill Affordability in Focus (3Q22 Earnings Wrap-Up) (November 2022)

North American Utilities, Power & Gas Rating Action Summary Report (Third-Quarter 2022) (October 2022)

What Investors Want to Know: Wildfires and California Investor-Owned Utilities (A Path to Upgrades Amid Record Wildfire Activity and Drought) (August 2022)

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Global Power
North America
Special Report

U.S. Utilities, Power, and Gas 2010 Outlook

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Related Research

- *Pipeline/Midstream/MLP 2010 Outlook, Dec. 3, 2009*

Table of Contents

Overview

The U.S. Utilities, Power, and Gas (UPG) sector 2010 outlook is framed in the context of Fitch Ratings' outlook for a slow U.S. economic recovery in 2010, with stable outlooks for most of the business segments within the UPG universe except for negative 2010 credit outlook for competitive generators and retail propane distributors. Forces driving the credit outlook are summarized below:

- Growth in power sales adjusted for weather will resume after the declines of 2008–2009. Natural gas sales volume is expected to be relatively flat year on year.
- Market prices for natural gas and electric power and capacity are likely to remain in a low band. Relatively low prices are:
  - Beneficial or neutral for electric and gas utilities.
  - Unfavorable for competitive power generators and natural gas storage and midstream services.
- While non-energy commodity prices are up from their trough in 2009, we do not foresee an overheated economy with rapid expansion in the prices of construction materials; however, U.S. dollar weakness is likely to raise costs of imported machinery and equipment, and could eventually raise prices of U.S. construction materials, increasing capital investment cost pressures.
- Electric utilities reduced their 2010 capital expenditure budgets from earlier planned amounts, but the overall level of investment remains greater than internal funding and will require external financing, including raising equity capital.
- Continued good access to debt and equity capital markets is expected, along with gradual improvement in bank market conditions.
- Electric and gas utilities are in a long-term cycle of rising unit costs, requiring frequent base rate increases to maintain stable financial results.
- While Fitch expects that most utilities will achieve reasonable regulatory outcomes, the dependence on rate increases exposes utilities to potential resistance from regulators, state politicians, and consumers/voters.
- Fitch expects passage within two years of national laws limiting greenhouse gas (GHG) emissions and possibly a national renewable portfolio standard, as well as more stringent environmental regulations on other emissions. This will have little effect on cash flow in 2010, but longer-term consequences for many competitive power generators are unfavorable, especially for owners of coal-fired generation, and it will add to cost pressures for integrated electric utilities and their consumers.

The "Credit Outlook Summary by Segment" table on page 2 of this report delineates the outlook and median rating with supporting bullet points for each business segment in the UPG sector. Fitch's business segment outlooks are formulated based on an analysis of fundamental factors, not by tallying the current rating outlooks of individual issuers in the business segment. Rating Outlooks for individual companies often vary from segment outlooks due to the specific circumstances of each entity. As of Dec. 1, 2009, more than 86% of individual issuer Rating Outlooks in the UPG sector are Stable.

Resilient Performance in 2009

Companies in the UPG sector weathered the recession and financial crisis of 2008–2009 with considerably less pain than sectors such as financial institutions, cyclical industrials, and retailers. The absence of significant defaults in the sector is in stark contrast to the upswing in defaults and bankruptcy filings across the rest of the U.S.

Credit Outlook Summary by Segment

The segment credit outlooks in the left column reflect fundamental analysis of factors influencing developments in the segment, not the aggregate Rating Outlooks of the entities in the segment. Median ratings indicated are based on the issuer default ratings (IDR) of entities rated by Fitch Ratings, with the exception of the public power utility segment, which is based on senior instrument ratings. Public power utilities are not assigned IDRs.

Segment	Drivers in Credit Outlooks for 2010
Utility Parent Companies Median IDR: BBB **Credit Outlook** Stable (One Year) Negative (Longer Term)	• Continued cost cutting for earnings and cash flow growth. • Investment focus on organic growth, investments in transmission, and renewables. • M&A activity will be limited. • Focus on core businesses; selective divestitures. • Equity issuance needed to maintain balanced capital mix.
Electric Utilities, Investor-Owned Median IDR Integrated Electric: BBB Median IDR Electric Distribution: BBB **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Sustained high capital spending for the majority of companies. • Relatively low gas and power prices will mitigate effect of rising infrastructure costs in 2010. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Serial base rate cases to recover infrastructure investments in 2010 and longer term. • Significant new debt, hybrids, and equity issuance to fund capex.
Gas Distributors, Investor-Owned Median IDR: A– **Credit Outlook** Stable (One Year and Longer Term)	• Oversupply of gas into the 2010 winter season will relieve rate pressure. • Sales growth constrained by continued weakness in the housing sector. • Capital expenditures will remain fairly low and manageable. • Expect consistent regulatory treatment and manageable external funding.
Competitive Generation Companies **Generating Companies and Energy Trading** Median IDR: BB– **Credit Outlook** Negative (One Year) Negative to Stable (Longer Term)	• Excess power reserve margins will linger with modest demand growth. • Low gas and power price environment will hold down margins for most generators. • Need to replace expiring hedges and contracts in a weak pricing environment. • Uncertainty surrounding carbon legislation remains a key operating and credit issue for this group.
Natural Gas Midstream Companies **Midstream and Pipeline Companies** Median IDR: BBB– **Credit Outlook: Pipelines** Stable (One Year and Longer Term) **Credit Outlook: Midstream** Stable (One Year and Longer Term) **Credit Outlook: Propane** Negative (One Year and Longer Term)	• Development of low-risk, contractually supported pipelines to connect increased shale gas production to high-demand eastern markets. • Midstream processing volumes and margins likely to be supported by significant price advantage of NGLs over oil-based naptha as ethylene feedstock. • Modest increase in volumes on natural gas and refined products pipelines due to recovering economic activity. • Companies are likely to continue to pursue conservative financial practices.
Public Power Utilities **Municipal, State, and Federal Agencies and Cooperatives** Median Rating[a] (Retail Systems): A+ Median Rating[a] (Wholesale Systems): A **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Benefit from less state regulatory oversight; local control over rate-setting. • Continued lower usage and decreased revenues from surplus power sales anticipated for 2010. • Growing pressure for local governments to slow rate increases and boost transfers from the utility system to replace lost city tax revenue and fund pension obligations. • Generation investment will continue, albeit at a slower pace. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Improving access to third party liquidity; expect extension of federal stimulus program which provides for issuance of taxable Build America Bonds by municipal entities.

[a]Median ratings shown for Public Power Utilities are senior unsecured debt ratings.
Source: Fitch.

economy, consistent with the defensive reputation of the sector.

In general, companies in the UPG sector entered 2009 in reasonably sound financial condition; some drew down their bank credit facilities during the banking crisis in late 2008 and repaid the loans as the bank and financial markets stabilized during 2009.

Rate-regulated utilities benefited during the market disruption from bond investors' preference for low-risk infrastructure investments. Regulated utilities and holding companies with higher investment-grade ratings had adequate to robust bond and commercial paper market access throughout 2009, and the bond market became more open to funding companies with speculative-grade ratings at progressively lower spreads during the second half of 2009.

Electric and gas utilities' sales volumes were reduced as a result of cyclical sales declines, especially lower industrial consumption of gas and power, with greatest impact in the Midwest. Residential demand was also lower, particularly in markets with the greatest impact from the housing collapse. While reduced sales hurt cash flow, lower costs of natural gas and power purchases, combined with timing differences in cost recoveries and collections of prior fuel deferrals, helped support operating cash flow and reduced working capital needs. Some integrated electric utilities that rely on spot sales of excess power into the wholesale market and rely on profits from wholesale sales suffered from a material decline in spot market prices.

Competitive generators and midstream gas processors were exposed to oversupply of natural gas and declines in power and gas spot and forward prices to the extent production was unhedged. However, generators and midstream processors that entered 2009 with their sales significantly hedged avoided most of the impact of lower margins.

Key Drivers of the 2010 Outlook

Fitch's 2010 credit outlook for the Utilities, Power, and Gas sector incorporates the following framing economic and capital market assumptions:

- General economic recovery continues over the course of 2010.
- Capital market conditions are expected to be open and the bank market to have a gradual improvement in spreads.
- Interest rates are expected to rise over the course of the year from very low levels.
- Weather-adjusted power demand expected to return to growth in 2010–2011. Power is expected to form a longer-term growth trend averaging about 1.4% to 1.6% per annum. Recovering industrial and commercial demand for natural gas should offset increased efficiency, resulting in flat sales overall for gas.

Fitch's 2010 U.S. economic outlook is for a slow recovery, with a projected modest 1.8% rise in GDP. Industrial production and GDP appear to be gaining, albeit from a low base. Fitch expects the pace of expansion to remain weak by the standard of prior recoveries. While job losses are slowing, unemployment is not improving, and could weigh on consumer sentiment and spending for several quarters. While there is a risk of a double-dip recession, which would continue to suppress sales growth in the sector and would result in a more adverse near-term credit environment, this is not Fitch's base case.

Interest Rates

U.S. Treasury interest rates in 2009 were at historically low levels, with short-term rates near zero for the first half of the year. Later in 2009, the long end of the yield curve began to move up. In the low rate environment, utilities achieved low-cost long-term debt financing, with 20- to 30-year taxable utility operating company issues at 5.50%–6%. As long as U.S. Treasury policy keeps rates low, the dollar would remain under pressure. Assuming that the economic recovery takes hold, the Federal Reserve would have to devise an exit from its easy-money monetary policy, allowing short-term interest rates to revert to a more normal level, and long-term rates to move up as well.

Access to Capital and Credit Markets

Access to the debt capital market is expected to remain open to the UPG sector issuers in 2010–2011.

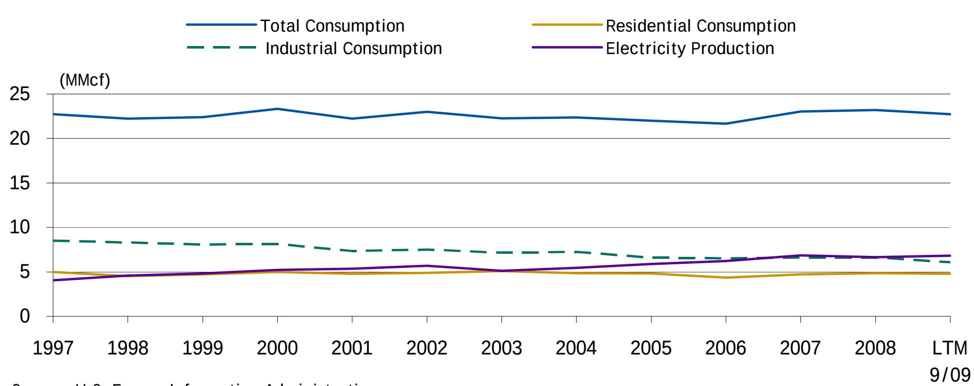
Access to equity capital in addition to debt will be critical for utilities and utility holding companies to maintain stable credit profiles, given the forecast for capital expenditures in the sector in excess of internal cash flow. The utility sector will have difficulty to satisfy equity investors' expectations for growth in a general economic recovery. Companies with strong market valuations or better growth fundamentals are better positioned to raise equity without excessive dilution. Many utilities are considering the use of hybrid securities to minimize dilution.

Fitch is monitoring expiring bank credit facilities and the pricing, covenants and terms of new and replacement facilities. A recent Fitch study tallied approximately $163 billion of credit facilities of companies in the UPG sector expiring in 2010–2014, with approximately 40% ($65 billion) of maturities concentrated in 2012. Fitch concluded that expiring credit facilities are not likely to create a liquidity issue for the sector, although credit costs are likely to be higher than prior to the credit crisis. Fitch expects that companies with expiring credit facilities will close the gap by means of alternatives such as diversifying credit providers and using new types of credit facilities, relying more on capital market debt and less on bank facilities for direct funding or back-up, and altering collateral-intensive business practices to reduce needs for back-up credit. (*For more on this topic, please refer to "Fitch Review of Bank Credit Facilities in the Utilities, Power, and Gas Sector," published on Oct. 28, 2009.*)

Gas and Power Demand

The trend over the past decade has been for declining natural gas consumption by industrial users to be offset by higher usage for power generation. In 2009, extremely low natural gas prices caused the dispatch of gas combined-cycle units to displace some production by less-efficient coal plants. Assuming somewhat higher gas prices in 2010, gas is likely to give back some share to coal at the margin. Beyond 2010, Fitch expects

U.S. Natural Gas Consumption by Customer Sector

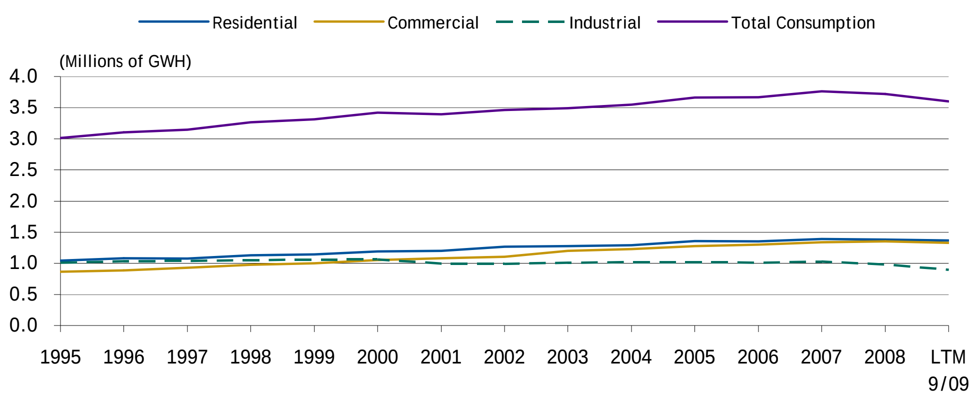


Source: U.S. Energy Information Administration.

that use of natural gas for power generation will be growing and taking share away from coal, offsetting shrinkage in primary demand for gas as a fuel for residential, commercial, and industrial applications. On balance, weather-adjusted sales of natural gas are forecasted to be approximately flat.

On a weather-adjusted basis, Fitch expects that U.S. electricity sales will rise in 2010 by 1% to 2%, largely due to a rebound in industrial usage straddling 2010–2011 that would recover some but by no means all of the industrial demand lost in 2008–2009. Longer run, Fitch foresees U.S. power consumption growing at 1.4%–1.6% annually. Growth in U.S. per capita electricity consumption has been in a long-term secular decline since 1960, and that trend is likely to continue as state and federal policies increasingly favor energy-efficiency and demand-reduction programs. In those states with aggressive policies promoting demand reduction, electric utilities are likely to press for tariff decoupling mechanisms to replicate those already in effect for many natural gas distributors and in a few jurisdictions for electricity.

U.S. Electricity Consumption by Customer Sector



Source: U.S. Energy Information Adminstration.

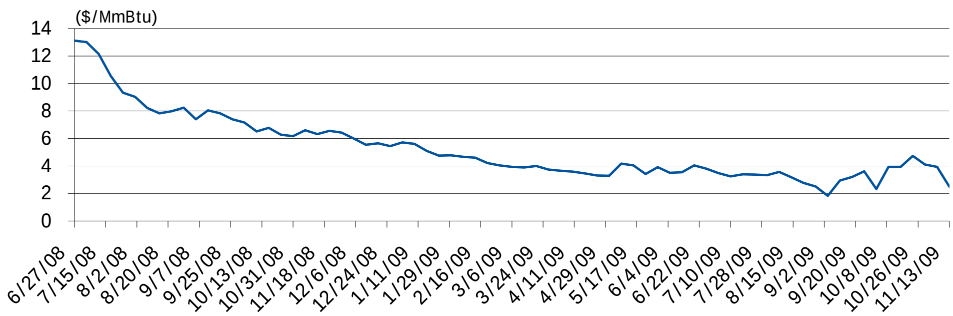
Commodity Prices

While market prices of gas and electric power are expected to rise from the 2009 trough, prices are likely to remain well below the levels that prevailed in early 2008. Relatively low gas and power prices are a favorable element in the credit outlook of most electric and gas distribution utilities and many integrated electric utilities, but form a more challenging market environment for competitive generators with conventional power generation assets and midstream gas processors to the extent that sales are dependent on market prices rather than contracts signed at more favorable prices.

Producers of steam coal remain in a pinch between their own rising production and pension costs and the gas-on-coal competition at the margin for power production. Coal stockpiles at power plants will enter 2010 materially above historical levels. While demand and prices for met coal can rise with global economic recovery, steam coal prices are likely to be constrained.

Prices of steel, cement, and other construction materials are up somewhat from their trough in early 2009, and prices are expected to increase over the course of 2010, especially due to the weak U.S. dollar. However, we see no basis for a return in 2010 to the runaway inflation of construction materials of early 2008.

Natural Gas Spot Prices — Henry Hub



MmBtu – Million British thermal units.
Source: Bloomberg.

Natural Gas Price Environment

Natural gas supply has exceeded demand for much of 2009, reflecting a combination of lower consumption, high production, and historically high gas inventory levels. Rapid expansion of shale gas production as well as greater accessibility to Rockies' gas production contributed to the 2008–2009 collapse of U.S. gas prices as the recession depressed industrial demand. Fitch believes that price weakness will continue throughout 2010 as the industry works through high inventory levels and demand remains weak; the dramatic reduction in rig count during 2009 may only gradually reduce the gas oversupply, especially since new shale production tends to have very high initial production levels.

Weather is a dominant factor in natural gas demand in the residential and commercial markets. Fitch does not forecast the weather; however, given the drops in natural gas demand in the industrial sector of the economy, it is not clear that even a colder-than-normal winter would be enough to support materially higher natural gas prices in 2010.

Wholesale Electricity Prices

As a result of the decline in U.S. power consumption in 2009 along with some new power capacity coming on line, capacity reserve margins have increased to the extent that all U.S. power regions are currently oversupplied, with capacity reserve margins in excess of 30% in most regions. Additions of renewable resources (largely wind) and a few large coal plants that came on line in 2009 or will enter service in 2010 also tend to prolong the industry overcapacity. Excess power capacity will only gradually be absorbed by the modest increase in power demand.

The relatively low band of natural gas prices foreseen for 2010–2011 is expected to combine with high capacity reserve margins to keep electric power and capacity prices in a moderately low range in 2010 compared with the prices that prevailed in 2007 through mid-2008. Increasing output of wind and solar generation over the next several years will also play a role in reducing round-the-clock energy prices and market clearing heat rates, especially in those markets with the most abundant resources of wind (Midwest and Plains, Texas) if transmission is adequate to move power to load centers. In 2010–2013, 30% or more of the new power generation coming on line in the U.S. will be wind, solar or other renewable generation, stimulated by tax subsidies, state renewable portfolio standards, and feed-in tariffs in some states. Finally, construction of new electric transmission facilities in New England and PJM and in ERCOT over the next five years is expected to begin to lower electricity prices in congested zones and to raise prices outside the congestion zones.

Capital Expenditures

Overall, companies in the UPG sector responded to the recessionary environment and reduced gas and power demand by deferring capital expenditures (capex) budgeted for 2009 and 2010 or cutting out discretionary projects, but the effects differ by segments within the sector. Overall, capex in the sector will remain well in excess of depreciation charges relating to the existing asset base.

- Capex for the competitive power generation sector remains in excess of depreciation charges, despite more limited access to capital by the independent generators as well as the court overturn of the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) regulations, which caused some companies to delay environmental compliance projects. In 2010, capex will include more environmental compliance work, investments in renewable power sources that carry abundant tax incentives and up-rates of existing nuclear plant capacity.
- Constrained by uncertain access to capital, gas midstream companies, and master limited partnerships (MLPs) reduced capex very sharply in 2009, cutting back to maintenance levels and completion of major projects already under construction. Some major pipeline infrastructure projects are under construction, and these have put some stress on credit ratios of their sponsors. In 2010, companies will spend to complete major pipeline projects and to extend gathering lines to new shale-producing areas, and could ramp up discretionary capex if funding is available and market conditions improve with enhanced economic activity.
- Gas distribution utilities generally have modest capex budgets, averaging around 1.5x annual depreciation charges. Spending is expected to decline year on year in 2010.
- Electric utilities have been in a pattern of increasing capex from 2005–2008 and had budgeted to continue to grow in 2009. In 2009, the investor-owned electric utilities reduced their aggregate capex by 10% from the originally budgeted 2009 levels, and cut their 2010 plans by 9% from the original plans for 2010. After those cuts, 2010 capital expenditures for the segment as a whole are now budgeted to be essentially flat with the record $84 billion level of 2008, and Fitch expects to see some growth in capex in 2011. The ratio of capex to annual depreciation and amortization charges will on average be higher for integrated utilities than for utilities that are pure transmission and distribution (T&D) providers. Fitch notes that there is considerable divergence in capital investment among the T&D utilities, including some that are investing heavily for advanced metering or transmission and grid reliability projects and several with very minimal capex. (*For more information on this topic, please refer to "Electric Utility Capital Expenditures: The Show Will Go On," published on Oct. 14, 2009*).

Ratio of Capital Expenditures to Depreciation and Amortization

(12 Months Ended Sept. 30, 2009)

	Average	Minimum	Maximum
Parent Companies (Consolidated)	2.3	0.7	4.9
Electric Integrated Utilities	2.7	0.8	6.7
Electric Distribution Utilities	1.5	0.3	4.6
Gas Distribution Utilities	1.5	0.9	3.0
Competitive Generators	2.8	0.9	7.0
Pipeline and Midstream Gas	2.5	1.0	7.6

Source: Fitch Ratings, company financial statements.

Public Policy Will Drive Fundamental Changes

While it is still uncertain whether a major energy bill will be enacted in 2010, the presidential administration and Congressional leadership are intent upon enacting a law to address climate change, including limits on GHG emissions using a cap-and-trade program, implementing standards for energy efficiency and conservation, and promoting investments in renewable resources. However, it has so far proven difficult to find bipartisan support or to muster sufficient support within the Democratic majority to pass a Senate bill that will raise costs for consumers and disadvantage some states more than others.

If the Congress is unsuccessful in passing new laws on these matters, the EPA has the authority to take a more vigorous approach to carry out the federal court mandate defining carbon dioxide and other GHGs as dangerous pollutants subject to regulation under the Clean Air Act. Compliance with an EPA rule is likely to be more difficult and costly for electric power generators and integrated utilities than a compromise bill crafted by Congress; thus, the electric industry has united to support Congressional action. Also, EPA is expected to act on new regulations to replace vacated Clean Air Interstate Rule and Clean Air Mercury Rule with important effects on coal-fired generating units, though not likely to have material effect in 2010.

Fitch assumes that there will either be a national law within the next two years that will regulate carbon emissions, or the EPA will step in with new regulations with more severe impact. If the EPA establishes rules, they are likely to take several additional years of litigation and implementation. Fitch conducts sensitivities of the effects of possible emissions prices or a tax on carbon emissions in its credit reviews of power generators, but has not developed stress cases around potential EPA regulations.

Renewable Energy and Technology Innovation

Roughly half the states have adopted renewable portfolio standards (RPS) requiring utilities to source a larger share of their electric power from defined renewable sources, and more continue to jump on the bandwagon. There is growing pressure in some states to establish feed-in tariffs and/or net metering of electricity. The longer-term effect of these requirements may be adverse for electric utility credit if utilities become loaded up with costly and inflexible power purchase obligations, akin to the problems that occurred in the 1980s–1990s following the implementation of the Public Utility Regulatory Policy Act of 1978. As higher costs of renewable resources and related transmissions are pushed into consumer tariffs, it could make it more difficult for utilities to achieve base rate increases to recover other rising cost elements and maintain satisfactory equity returns.

In 2009, significant tax incentives (*see the Federal Tax Matters section on page 9*) have begun to stimulate a sharp increase in investments in wind, solar, biomass, and other resources defined as renewable power. Federal loan guarantees for renewable resources, advanced clean energy technologies, and electric transmission, as well as grants from the Department of Energy for advanced metering and Smart Grid projects are additional sources of stimulus.

We have entered a period of high technology innovation in renewable energy resources, demand reduction, energy efficiency, and electric power transmission networks. A significant amount of work is underway to prepare for potential charging of plug-in electric vehicles, a development that would require substantial new investments in the utility distribution grid. The industry is testing technologies for carbon capture and storage, integrated gasification with combined cycle electric production (IGCC), battery storage, and pursuing licensing of new nuclear reactor designs. The U.S. has increased federal funding for energy-related research at the national laboratories. Burgeoning and often conflicting policies and technology changes will lead to fundamental and largely unpredictable changes in the energy and electricity sector over the next five to 10 years, but with relatively small impact in 2010.

Federal Tax Matters

Many companies in the UPG sector will lower their tax bills for 2009 and 2010 as a result of a host of economic stimulus tax provisions. Tax credits for investments in renewable energy and extended tax loss carry-backs will temporarily turn the tax return into a profit center for several companies in the sector.

The American Recovery and Reinvestment Act of 2009 (ARRA), an economic stimulus package, extended and expanded tax benefits available to specific project investments, particularly for various renewable energy technologies:

- **Renewable Energy Production Tax Credits (PTC):** ARRA extended eligibility dates of a tax credit for facilities producing electricity from wind, biomass, geothermal energy, municipal solid waste, and qualified hydropower and marine renewable energy. The "placed in service date" for wind facilities was extended to Dec. 31, 2012, and for the other types of facilities to Dec. 31, 2013.
- **Election of Investment Tax Credits in Lieu of PTC:** Businesses that place in service facilities that produce electricity from wind and some other renewable resources can choose either the energy investment tax credit (generally a 30% tax credit for investments in energy projects) or the PTC, which provides a credit per kWh for electricity produced from renewable sources. A business may not claim both credits for the same facility. A taxpayer electing the ITC in lieu of PTC receives a cash payment 60 days after achieving the commercial operation date.
- **Bonus Depreciation:** Businesses can deduct half the adjusted basis of qualifying property in the year it is placed in service. The extension applies to qualifying property placed in service in 2009 (2010 for long production period property and certain transportation property).

Net operating loss (NOL) carry-back was extended for a maximum carry-back of 5 years rather than the normal two-year period applicable to nearly all companies, except for recipients of TARP relief, as a provision of the Homeownership and Business Assistance Act of 2009 (November 2009). The carry-back can be applied to NOLs generated in either 2008 or 2009 but not for both years. The effect is an immediate increase in available cash for the taxpayer.

Meanwhile, the prior administration's dividend tax cut is scheduled to expire at the end of 2010, and there is wide speculation that additional taxes or higher tax rates will be applied to fund the federal deficit, including eliminating the current favorable treatment of capital gains and dividend income. Given the sector's heavy capex requirements, Fitch would consider any such changes in federal income and capital gains tax rates to be unfavorable developments that would likely lower equity valuations of regulated utilities and utility holding companies.

Pension Funding

Many companies that entered 2009 with severe erosion in the value of their pension funds relative to projected benefit obligations opted to make cash contributions to comply with the U.S. Pension Protection Act of 2006, as moderated by the Worker, Retiree, and Employer Recovery Act of 2008. Cash contributions in 2009, combined with the recovery in bond and stock market values, have reduced the gap, but a number of companies will need to continue cash contributions in 2010 (absent a significant run-up in market values of investments).

Bankruptcy and Restructuring

There were no notable defaults or bankruptcy filings in the UPG sector in 2009. That stands in sharp contrast to the upswing in defaults and bankruptcy filings in other corporate sectors as a result of the severe national and global recession. A peak default period in the UPG sector was from 2001–2003.

SemGroup restructured and emerged from bankruptcy as a new public company in early December 2009, approximately 16 months after the company and its major wholly owned subsidiaries filed a bankruptcy petition on July 22, 2008. Pre-petition lenders were estimated to recover 100% on some secured obligations and secured trading exposures, an estimated 55% on one secured working capital loan facility, and 75% on a secured revolving credit. Unsecured lenders and general creditors were estimated to recover 5% to 10% of their exposure via the allocation of 5% of the equity in the new public company to the unsecured class.

SemGroup's 2008 insolvency resulted from its inability to post required margin collateral to trading counterparties. The company adopted a trading strategy based on the sale of naked call and put options that did not adhere to the SemGroup risk management policy and violated the terms of its pre-petition credit agreement. When SemGroup experienced trading losses, it increased and rolled forward its options positions, causing increased losses and occasioning growing demands for margin collateral that the company could not satisfy.

Utility Parent Companies

2010 Outlook — Stable
Longer-Term Outlook — Negative

The utility parent companies (UPCs) are poised for an improved economic and financial environment as compared to that of a year ago. With economic activity picking up, industrial sales have shown signs of stabilization in the third quarter. As industrial sales recover, it is likely that the commercial sales, which have been weak in certain regions, could follow suit. However, with revenue growth rates well below historical levels, Fitch expects UPCs to continue their cost-cutting focus in both their regulated and unregulated businesses to drive earnings and cash flow growth or support stability.

UPCs have withstood the credit crisis well. Overall, the companies were in a financially sound situation before the credit crisis hit, and liquidity during 2009 was bolstered by reduced working capital needs due to falling commodity prices, reduction in discretionary capex, and capital market issuances. Access to capital markets remains open and relatively low cost for creditworthy borrowers. Fitch expects UPCs to extend their conservative balance sheet stance in 2010, given the current fragile nature of economy and recovering credit markets, combined with the stated intentions of most management teams to maintain a stable credit profile. For regulated businesses, Fitch expects the utility parent companies to use a judicious mix of debt and equity to finance high levels of planned investments, most of which is mandated and earmarked for reliability, environment compliance, and renewable energy projects. For unregulated businesses, UPCs will need to balance the capital structure against rising business risk due to lower cash flows brought on by a fall in commodity prices and increasing proportion of unhedged output in the outer years.

Fitch expects climate change to remain a predominant focus for most UPCs despite the uncertainty around the contents and timing of passage of a national law. While some UPCs have been more proactive than others, Fitch expects more and more companies to pursue low/zero carbon technologies more aggressively than before. This could be manifested in both regulated and unregulated businesses investing a greater proportion of total capex in clean technologies and renewable generation as well as associated transmission, energy efficiency, and smart grid investments, and in retirements of older coal-fired power plants that cannot be economically retrofitted.

Parents of utilities are generally taking advantage of opportunities to invest in regulated rate base, driven by legislative/regulatory mandates as well as a strategic pursuit of cleaner technologies as highlighted above. Fitch expects UPCs to seek out those investment opportunities where prospects of cost recovery are high and the prospect is for a reasonable return on equity (ROE).

As of late November 2009, utility stocks as measured by the Philadelphia Utility Index (UTY) have declined 3% in 2009 and underperformed the S&P 500 by 18%. The increase in risk appetite among investors clearly worked against the defensive utility sector as signs of economic recovery emerged. Utility stocks that have a greater proportion of unregulated businesses have lagged their regulated peers due to a sharp fall in commodity prices. The sunset of reduced dividend tax rates on Dec. 31, 2010 further reduces the investment appeal of utility equity and is expected to increase the cost of equity capital.

Notwithstanding the turmoil in the economy and the adverse capital market conditions, especially in the early part of 2009, ratings in the UPC sector have remained generally stable. The UPC's median 'BBB' issuer default rating (IDR) and senior unsecured ratings are the same as a year ago. Year to date, there have been three upgrades and seven downgrades in the sector. Approximately 82% (37 of 45 observed companies) of Fitch's UPC issuers have Stable Rating Outlooks and 16% (seven of 45) have Negative Outlooks, while only 2% (one of 45) has a Positive Outlook.

Sector downgrades in 2009 reflect a challenging operating and financial environment due to both weak industrial sales and rising operating costs (NISource Inc.; IDR 'BBB–'/Stable), financial pressure, and associated execution risk from plans to build new nuclear plants (SCANA Corp.; IDR 'BBB+'/Stable), weak commodity prices, and lower profitability of the unregulated generation portfolio (PEPCO Holdings Inc.; 'BBB'/Negative), and reassessment of financial and liquidity risk (Constellation Energy Group, Inc. (CEG); 'BBB–'/Stable) among others. Fitch upgraded only three IDRs of parent holding companies in 2009. Two reflected gradually improved financial ratios and favorable state regulatory developments (Avista Corp.; IDR 'BBB–'/Stable and DPL Inc.; IDR 'A–'/Stable), and one resulted from demonstration of support by a foreign parent (Energy East Corp.; IDR 'BBB+'/Stable).

Ratings are not anticipated to change meaningfully in 2010. Fitch expects the overall ratings for the UPCs to be stable primarily due to modestly rising economic activity, and managements' relatively conservative financial and business strategies. Concerns would be a fall in economic activity and power demand, an increase in populist regulatory decisions, volatile commodity prices, adverse climate change mandates, and shareholder-friendly decisions that result in increased leverage.

Mergers, Acquisitions, and Divestitures

Fitch expects limited merger & acquisition (M&A) activity in the near term given uncertainties that remain around economic recovery, commodity prices, state regulatory responses, and carbon legislation, combined with the high costs of bank financing and relatively low equity valuations. Exelon Corporation's (EXC) failed bid to acquire NRG Energy, Inc. (NRG) in 2009 highlights the difficulty in pulling off a hostile deal. The ongoing delay for Entergy Corp.'s spinoff of Enexus is reflective of the difficult state regulatory environment related to M&A activities. Electricité de France's investment in a 49.99% joint venture interest in Constellation Energy Group's nuclear fleet was consummated late in 2009, after a controversial state regulatory proceeding that highlighted the regulatory hazards of merger/divestiture activity. That said, the case for industry consolidation remains strong given the fragmented industry, the scale of capital investments needed relative to the size of the companies, and the potential for operational synergies to drive down rates for consumers.

Fitch expects a majority of the UPCs to focus on organic growth, especially as regulated businesses take advantage of the attractive incentives for renewables and transmission development to drive rate base growth. As demands on capital increase, some UPCs could shed non-core assets, including businesses that are collateral intensive.

On the unregulated generation side, while there are good arguments for consolidation of smaller gencos, we see greater potential for asset acquisitions given low valuations. This could be driven by unregulated generators seeking "tuck-in" acquisitions or utilities short of generation seeking to grow their rate base. An emerging trend seems to be for unregulated generators to acquire renewable assets, such as the recent announcements by NRG to acquire an offshore wind developer and a solar farm in California and CEG to purchase wind assets in Maryland. It is quite possible that different forms of partnerships develop between traditional utility companies and the new generation clean technology companies to exploit relative strengths. Finally, a weaker dollar could spur cross-border asset acquisitions by foreign buyers or joint venture investments with foreign participants. Notable recent announcements of cross-border partnerships are AES Corporation selling a 15% stake to China Investment Corporation and Duke Energy signing agreements with several Chinese companies to develop a variety of renewable and clean energy technologies.

Electric Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's near-term outlook for the utility sector is stable, despite some challenges. The combination of high capital expenditures and relatively weak electricity demand will continue to pressure credit quality and require base rate increases in 2010 and beyond. Favorably, most regulated utilities are entering 2010 on sound financial footing. Moreover, overall rate pressures are mitigated by low fuel prices, strong capital market access, and low interest rates. Fitch's stable outlook assumes most states will continue the constructive regulation of recent years. However, given the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects.

Regulation

Decisions by state regulators will continue to be a key driver of individual company credit ratings in 2010. In general, state regulation is likely to continue to be even-handed; however, there could be isolated cases of adverse regulatory or politically motivated decisions on utility rates in an election year, which is considered to be event risk rather than a sector trend. Positively, low fuel costs should largely offset the impact of rising base rates in 2010. However, even with modest electricity demand growth next year, total customer demand is expected to remain below 2007 levels, and under-earning seems likely, even in the case of some companies that have base rate cases decided in 2009 and 2010. Some of the rate requests filed in late 2008 or early 2009 and still pending were made prior to the recognition of the full impact of recessionary load loss on demand; consequently, utilities are already playing catch up by seeking ways to cut operating costs and/or defer capex.

Numerous electric utilities have filed for base rate increases to recover costs of investments in system growth and reliability, as well as to adjust the allocation of operating and maintenance costs and capital recovery to lower demand levels. In addition, a number of multi-year rate settlement periods will end, enabling these utilities to deal with the rising costs and loss of load. Numerous state commissions are expected to reach decisions on new base rates in 2010. (*See the "Electric Rate Case Pending 2010 Decision" table below.*)

Electric Rate Cases Pending 2010 Decision

Arizona Public Service Company	Indiana Michigan Power Company
Atlantic City Electric Company	Monongahela Power Company
Black Hills Power, Inc.	New York State Electric & Gas Corp.
Central Hudson Gas & Electric Corp.	Northwestern Corporation
Connecticut Light and Power Co.	PacifiCorp
Consolidated Edison Co. of New York[a]	Potomac Edison
Delmarva Power & Light Co.	Potomac Electric Power Company
Duke Energy North Carolina	Public Service Co. of New Hampshire
Empire District Electric Company (MO and AK)	Public Service Electric and Gas Co.
Florida Power and Light Co.	Rochester Gas and Electric Corp.
Florida Power Corp.	Southwestern Electric Power Company (AK and TX)
Georgia Power Company	Union Electric Co.
Illinois Power Company	Western Massachusetts Electric Co.

[a]A settlement proposal is pending.
Source: C Three Regulatory Database, Fitch Ratings.

An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent softness of demand and state policies that include ambitious energy-efficiency targets. Tariff mechanisms that mitigate the effect of variances in sales are common among gas utilities, which have experienced declining demand for many years and whose sales have an extreme weather sensitivity; in gas distributors, this may take the form of minimum bills that recover a large part of fixed costs, fixed/variable tariff components, or explicit weather normalization or volume decoupling mechanisms. While such tariffs have not been common for residential consumers of electric utilities, Fitch sees states beginning to implement some mechanisms of this sort on the electric side, although in a few cases at a pilot scale. States that allow or initiated electric decoupling programs include: California; Ohio (Ohio utilities can request decoupling under existing rules), Vermont, New York (Consolidated Edison of NY, Orange & Rockland Utilities, Central Hudson Gas and Electric), Maryland (Baltimore Gas & Electric); and pilot scale programs in Wisconsin and Idaho. In Fitch's view, volume decoupling reduces cash flow volatility and lowers business risk, and will be particularly meaningful in states that have set aggressive energy reduction goals.

For electric T&D utilities in states that restructured their electricity markets, staggered power auctions or other competitive power procurement processes are becoming more customary and standard. Staggered contracts for up to three years create realized prices that are a blend of past and future prices, which moderates single-year commodity price volatility for customers. Most states that deregulated generation supply have already completed or are nearing completion of full transition to market-based generation rates. Solicitations for energy, capacity, and/or other services in the next six months are expected to include Duquesne, Metropolitan Edison/Penelec, Penn Power, PPL Electric Delivery, Philadelphia Electric Co., Illinois Power Agency, West

Penn Power, and the New Jersey Basic Generation Service auctions for the state's electricity utilities. While in prior years' outlooks, Fitch noted significant uncertainty regarding the ability of electric T&D utilities to obtain full and timely pass-through of generation costs in tariffs, this risk has subsided as auctions that place the price risk with consumers have become routine; the significant decline in wholesale market power prices has also helped to make the transition less controversial than in prior years.

Capital Spending

While many utilities responded to the economic downturn and court decisions that set aside the CAIR and CAMR by reducing or deferring capital spending budgets for 2009 and 2010, capital spending remains high relative to historical trends. In many cases, utility managements responded to weak demand by adjusting budgeted expenditures to accommodate lower demand curves and deferring, but not cancelling, new generation projects; however, projects to enhance distribution reliability generally were not delayed. Despite these deferrals, Fitch forecasts spending will continue to run at more than double depreciation on average. To fund the system investments, internal cash flow will need to be supplemented with external capital, and management will face choices of increasing leverage or shoring up the capital structure with new equity issuance.

Drivers of 2010 capital spending levels for electric utilities include: increasing environmental compliance mandates; new transmission lines needed to serve intermittent renewable power sources located far from load, reduce basis differentials within regional transmission organizations (RTO), or improve system reliability; advanced metering; and self-building for renewables mandates. Fitch notes that for integrated utilities with responsibility for generation as well as power distribution, 2009 capital spending averaged approximately 2.7x depreciation of existing assets, while for restructured electric T&D utilities, capex averaged a more manageable 1.5x depreciation charges (see the "Capital Spending Relative to Depreciation Charges" table on page 6). Fitch notes that utilities have good track records for full and timely recovery of environmental spending and that recovery of the transmission investments is often supported by RTO orders to build and constructive Federal Energy Regulatory Commission (FERC) tariffs, which are both significant spending categories for 2010.

Fitch believes capital investments will remain elevated for several years. Global climate change and GHG legislation is going to present enormous challenges to the industry over the intermediate to longer term, as utilities consider their options to comply with anticipated reductions in emissions, such as carbon capture and sequestration, integrated gasification combined-cycle power generation (IGCC), up-rates of existing nuclear plants or new-build nuclear, or renewable energy resources (27 states, and counting, have enacted RPS standards). While the low gas price environment makes power generation with natural gas an easy choice for near-term capacity needs and to back up intermittent wind or solar power, utility managements and state regulators are leery of renewed gas price volatility if eventually the oversupply of natural gas should self-correct. Moreover, gas is not a carbon-free choice, and longer term carbon goals under a national energy bill would not be met if load growth is mainly met through gas-fired capacity additions. Uncertainty about what to build and when is exacerbated by unknown impacts of energy efficiency and electric car efforts, and when pressures on customer bills from carbon allowances will ramp up to a meaningful level. The rating impact of these longer-term developments will be case by case, based on legislative and regulatory integrated resource plans and cost recovery decisions. For example, Ohio passed a law requiring future costs of carbon laws to be passed through to customers in the fuel adjustment mechanism, an encouraging sign for the credit of integrated electric utilities in the state.

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Corporates

Natural Gas Distributors

2010 Outlook — Stable
Longer-Term Outlook — Stable

Fitch's 2010 outlook for local gas distribution companies (LDCs) remains stable with expectations for continued operating, regulatory, and financial stability within the space in the long term. Natural gas prices have moderated as the quantity of gas in storage has hit historic highs heading into the 2009–2010 winter heating season. This will mean lower rates for consumers, alleviating some concern regarding rising bad debt expense given high unemployment and weakness in the economy. Additionally, state regulatory relations continue to be constructive for gas LDCs; many LDCs continue to successfully pursue progressive rate design crafted to stabilize financial exposure to changes in volumes sold.

Overall, gas LDCs weathered last year's capital market turmoil maintaining liquidity and access to capital markets. Gas prices were well off their mid-2008 highs by the start of the 2008–2009 heating season, and LDCs had delayed building inventory. Also, Fitch's concerns about increased bad debt expense in 2009 did not meaningfully materialize. Sales growth for the sector slowed significantly as the recessionary economy and a weak housing market slowed customer growth across the board. Continued weakness in the housing sector will constrain demand throughout 2010. Sales volumes have also been affected by a significant decline in industrial demand, particularly in the U.S. Midwest.

Fitch expects that moderate economic growth should help return industrial demand to more normalized levels in the second half of 2010. As a result of slower growth and slackened demand, LDC capital expenditures are expected to be focused on system maintenance rather than expansion and should remain fairly low (averaging approximately 1.5x depreciation charges), so there is not a need for significant external funding. The relatively low capital spending, coupled with lower rates charged to consumers via purchased gas cost adjustment mechanisms, will reduce the chance for any potential rate shock to customers and limit LDC exposure to adverse regulatory developments. Additionally, competitive energy sources, including fuel oil and propane, are correlated to crude oil prices and thus remain priced well above natural gas, limiting the potential for fuel-switching during 2010.

Conservation and the impact of weather on usage remain industry-wide concerns for natural gas LDCs, many of which have pursued rate designs in their regulatory jurisdictions intended to help address usage volatility. Currently, 18 states have approved the implementation of revenue decoupling, which helps prevent margin erosion stemming from declines in customer usage due to conservation or energy-efficiency increases. Additionally, more than half of U.S. states have some form of either full decoupling or weather normalization, which helps stabilize revenues from the effects of weather. These rate designs help insulate the utility's cash flow from changes in volume of sales, providing earnings and cash flow consistency and stability. Fitch continues to view the implementation of rate mechanisms that reduce cash flow volatility favorably; more predictable cash flow translates to lower business risk for LDCs.

Competitive Generation Companies

2010 Outlook — Negative
Longer-Term Outlook — Stable

Fitch's 2010 outlook for competitive generation companies is negative, as continued demand and price weakness will weigh on cash flow and credit metrics. Fitch typically views the competitive generators in two distinct subgroups: affiliated generators, which are subsidiaries of large utility holding companies or financial institutions and typically have investment-grade IDRs; and independent generators, which are standalone companies that typically have speculative-grade IDRs. Fitch's 2010 outlook is negative for both subgroups. Fitch expects that continued power price weakness, slack demand, and uncertainty surrounding carbon legislation will all weigh on the credit outlook for the competitive generating space throughout 2010. Fitch believes that earnings and cash flow, while likely improved over 2009 results, will continue to be muted, barring any significant recovery in commodity prices or industrial demand.

Last year proved to be a challenging environment for competitive generators across the spectrum. Lower demand and wholesale power prices pressured earnings and cash flow, particularly for some of the more highly levered independent generators, who in some cases were forced to sell assets, pay down some debt, and amend credit facility covenants. Dynegy Inc., for example, amended the covenants under it secured credit agreement and announced an agreement with LS Power to sell assets in exchange for cash and LS Power's class B units in Dynegy. These moves precipitated a negative rating action by Fitch in August when the transaction was announced. Negative rating and Outlook actions, in fact, were prevalent for many of the independent generators and affiliated generators under Fitch coverage, with a downgrade to Dynegy Inc. (DYN; IDR: 'B–'/Negative Outlook) and Outlook changes to Ameren Energy Generating Co. (IDR: 'BBB+'/Negative Outlook), Brookfield Renewable Power (BRPI; IDR 'BBB–'/Negative Outlook), Edison Mission Energy (EME; IDR: 'BB–'/Rating Watch Negative), Midwest Generation (IDR: 'BB'/Rating Watch Negative), RRI Energy (RRI; IDR 'B'/Negative Outlook) and Texas Competitive Electric Holdings (TCEH; IDR: 'B'/Negative Outlook).

Despite the discouraging fundamentals for this business segment, Fitch believes that the competitive generators have taken steps that will tend to mitigate further downside should wholesale power prices continue to languish through the year. The independent generators, in particular, have focused on cutting operating costs and hedging or contracting significant amounts of their expected generation for 2010 and 2011, actions that some of the companies had not previously taken in a more robust wholesale power pricing environment. Liquidity across the space remains adequate with most companies possessing sizable cash balances and revolver availability. Fitch also notes that despite declines in value from the peak in early 2009, enterprise valuations for most power generators are strong relative to outstanding indebtedness, which would lead to strong recoveries for secured debt for all but the most highly leveraged competitive generator issuers in a case of default.

Capital spending will remain muted as generators continue to take a conservative approach to growth spending, and environmental spending is delayed given the uncertainty surrounding carbon legislation and absent new mercury and sulfur dioxide rules. Notable exceptions include NRG, which continues to pursue its Repowering NRG capex program and has recently been an active investor in renewable resources; TCEH, which is in the process of completing the third of three large baseload power plants; and Exelon Generation Co., which is pursuing a large-scale nuclear up-rate program. Additionally, Fitch sees the potential for opportunistic asset sales and acquisitions, as more highly leveraged generators look to shore up balance sheets or more stable names look to grow and diversify their portfolios. With equity prices not reflecting the value of underlying assets, Fitch continues to believe there is a compelling argument for consolidation and acquisition within the space.

Longer term, looming carbon legislation remains a key operating and credit issue for the competitive generating space. The financial impact could be significant depending on the individual company's generation portfolio, as well as the specific form and cost assigned to emissions under proposed legislation and the direction of commodity prices. While the impacts of carbon legislation will vary for individual companies and in different power regions, it is reasonable to assume that less-efficient coal-fired generation will begin to be displaced first by gas-fired generation and, in the longer term by renewable projects, new nuclear, and potentially by carbon capture and sequestration clean coal technology (should that technology prove to be economically viable). Emission-free competitive generators with low variable-costs will be the biggest beneficiaries of carbon legislation. More-efficient natural gas-fired competitive generators are likely to see their generation dispatched more frequently as well.

Longer-term concerns include debt, credit facility, and term loan B maturities in the 2013–2016 timeframe; the roll off of current hedges; and the ability of competitive generators to recontract expected generation at levels that would support ratings. Debt maturities in 2010 are manageable, as most issuers do not face any significant refinancing. Additionally, with capital markets returning to a more normal pattern, access to capital should be open. However, particularly for the speculative-grade independent generators, capital will likely be significantly more expensive than prior to the financial crisis, reflecting changes in the bank market conditions, higher financing costs and weak equity valuations.

Public Power Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's Public Power and Electric Cooperative 2010 Outlook — Stable

Fitch's 2010 outlook for the public power and electric cooperative sectors continues to be stable despite the pressures that correspond with the national economic recession. After a rocky first half of 2009, capital market access has stabilized. However, there appears to be a lagging ripple-effect from the economic downturn that is working its way through local governments and creating downward rate pressure on public power utility systems that will persist well into 2010. Other credit pressures on the sector include: declining energy consumption related to the economic downturn, the need for rate increases in a difficult economic climate, limited/costly access to external liquidity, and state specific mandates — with the potential for federal mandates in 2010–2011 — regarding renewable energy sources and GHG emissions.

These pressures coincide with declines in natural gas and purchased power prices that have reduced the expenditure levels and provided some relief to many retail utilities. However, a softening of power market prices has resulted in lower-than-budgeted revenues from surplus power sales for several utilities. Growth levels have favorably slowed to more manageable levels in certain regions, providing an opportunity to adjust and re-evaluate system capital needs. While these current trends have not resulted in significant changes to the credit quality of the overall public power and electric cooperative sectors, Fitch intends to monitor variations specific to regions. Fitch notes that events in the next five to 10 years primarily related to expected environmental legislation could increase the cost structures of many electric utilities and potentially place pressure on credit ratings. Decisions regarding timely rate recovery of increased costs and the subsequent change in a utility's competitive position within its regional market will be key credit drivers. Fitch believes that the public power business model will continue to allow these utilities to perform well in 2010 and provide investors with a generally stable credit sector. Fitch's outlook for the sectors over the long term remains stable yet recognizes that increasing negative pressures are affecting the industry, primarily due to environmental mandates related to increased renewable energy resource requirements and GHG emissions restrictions. The possibility of carbon legislation being enacted looms over the public power industry and the specter of the proposed legislation is already impacting decisions on whether to build additional fossil-fuel baseload generation.

Short-Term Public Power Outlook

While there have been noticeable downward trends in financial metrics such as debt service coverage, cash-on-hand, and operating margins for both wholesale and retail public power systems, overall the sectors continue to benefit from solid credit fundamentals, including: essentiality of electric service, local control over rate-setting without state commission oversight, a cost advantage compared to neighboring investor-owned utilities, and benefits associated with a predominantly residential and commercial customer bases. Fitch expects that the average ratings for wholesale and retail utility systems, including electric cooperatives, will continue to be ‘A’ and ‘A+’, respectively. Fitch has noted in certain regions an increase in efforts by local governments to slow electric rate increases and boost transfers from the utility system to replace lower tax revenues and to fund the growing local government pension obligations. If unchecked, this trend could result in public power utilities with reduced liquidity and credit protection.

While varying in degree from region to region, overall the economic downturn and financial market disruptions have not yet resulted in material credit pressure on public power utilities. Public power and electric cooperatives have continued to have access to the capital markets, although borrowing costs have been higher than budgeted. Construction costs have declined and, in some cases, capital spending has been delayed. Generation investment is continuing, albeit at a slower pace, both through direct ownership and long-term bilateral contracts. Supply-related investments have been designed not only to meet load growth but increasingly to comply with local and state renewable resource requirements. Many utilities continue to realign their debt structure by reducing outstanding variable-rate exposure, given the disruptions in that market and the contraction/costliness in available liquidity facilities.

The economic contraction in many markets resulted in slower growth levels and consumption declines. Collection delinquencies and turn-off actions have increased only slightly despite the negative economic conditions, rising unemployment levels, and home foreclosures. Public power and electric cooperative utilities that are commodity purchasers have benefited from the recent decline in natural gas and wholesale power prices. However, several utilities that typically sell excess power into these markets have experienced lower-than-budgeted revenues from surplus sales, but many have maintained their financial margins through the use of conservative forecasting and budgeting practices, given the volatility of these revenue sources.

Long-Term Public Power Outlook

Fitch’s long-term outlook for the sectors is stable but recognizes increasing negative credit pressures. Approval of national environmental mandates is still pending; however many utilities already face pressure from state or locally established renewable portfolio standards and must assess how to meet long-term load growth within an evolving environmental and generally more restrictive and costly regulatory framework. The growing pressure to enact carbon emissions restrictions to combat global climate change is expected to result in the enactment of national carbon legislation in the near future, but the structure, timing, and implementation schedule is still uncertain. Utilities, however, are already making decisions based on the anticipated legislation. Several large, baseload coal-fired power plants have been cancelled, and some of this planned future capacity is being replaced by natural gas and renewable generation. To the extent public power utilities rely mainly on natural gas-fired resources going forward, Fitch believes there could be a renewed risk of over-reliance on natural gas and the associated volatile fuel price exposure.

While Fitch believes that the public power and electric cooperative business models will continue to allow these utilities to perform well and prove to be stable credit sectors, increasingly negative market and industry factors could adversely impact some regions more than others. The utilities with greater credit exposure are those that have large capital improvement needs, relatively high leverage, below-average financial and rate flexibility, and a heavy reliance on fossil fuel generation. Conversely, systems that show stable to improving financial metrics, have limited new capital needs, and have a greener generation portfolio are expected to maintain Stable Outlooks and in some cases realize improved credit profiles.

Pipeline and Midstream Sector

Companies in the Pipeline/Midstream segment in 2009 faced the following pressing concerns: adequacy of liquidity, access to capital markets, the oncoming recession and its effects on demand for energy products, ability to defer capital spending, and commodity price trends. In response to these difficult operating conditions, companies overwhelming "played defense" and adopted cautious financial practices. In the face of a weakening economy and constrained capital markets, companies issued high-cost debt and equity to shore up their liquidity positions. Discretionary spending was cut to sustainable levels. Many MLPs adopted more conservative distribution practices to increase cash retention.

Entering 2010, business fundamentals are better than they were six or 12 months ago, but many challenges remain. Growth has slowed. Several large pipeline projects, burdened by increased construction and capital costs, will generate lower-than-expected, single-digit returns. The economy remains fragile. Given this backdrop, Fitch expects companies to stay the course by avoiding excess leverage and maintaining disciplined operating and growth strategies.

Natural Gas Pipelines

2010 Outlook — Stable
Longer-Term Outlook— Stable

Fitch foresees stable short-term and longer-term outlooks for interstate and intrastate natural gas pipelines. However, credit measures for companies funding large expansion projects will likely remain under pressure through 2010.

During 2008, completions of new natural gas pipelines and expansions of existing pipelines in the U.S represented the greatest amount of pipeline construction in more than 10 years. The added capacity for each of the top 15 projects exceeded 1 billion cubic feet per day (Bcf/d). The U.S. Energy Information Administration (EIA) reports that the number of proposed projects suggests construction activity will remain strong through 2011, with 2009 potentially showing the second-highest level of capacity additions in the decade. More than 10,200 miles of potential new gas pipelines are scheduled to be added in 2009–2011, but a portion of these projects will likely be delayed or canceled.

Even with cuts in discretionary spending by sponsor companies, weak commodity prices, and a slowly recovering economy, there is still a demand for new pipeline infrastructure to access unconventional resources, particularly natural gas from shale formations. Additionally, the costs of steel pipe, equipment, labor, and financing have declined from 2008–2009 highs, which will help companies attain adequate returns on their investments.

New North American Pipeline Capacity

	Proposed for 2010			Proposed for 2011		
	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles
Central	3,655	1,820	871	1,528	491	290
Midwest	0	0	0	2,067	1,416	254
Northeast	2,491	1,276	249	4,318	2,465	599
Southeast	9,911	2,006	601	9,364	3,748	1,000
Southwest	6,283	577	293	13,915	2,162	688
Western	345	107	27	5,276	5,377	1,686
Mexico/Canada	1,920	N.A.	29	980	49	41
Total	**24,605**	**5,786**	**2,070**	**37,448**	**15,707**	**4,528**

N.A. – Not available.
Source: Energy Information Administration.

Products Pipelines

2010 Outlook — Stable
Longer Term — Stable

The pace of the economic recovery will affect demand for oil products and transportation volume, affecting crude oil and refined products pipelines. However, following reduced throughput in 2009, Fitch expects product demand to stabilize.

Midstream Services

2010 Outlook — Stable
Longer Term — Stable

For natural gas gatherers, both the short-term and long-term outlooks are stable, while for gas processors the short-term outlook is negative. After several years of high processing margins, in late 2008 natural gas liquids (NGL) unit margins dropped. While margins have recovered back to more historical norms, future commodity margins are uncertain. Financial performance for some companies will also be affected by hedging practices and their economic sensitivity to natural gas prices. Fitch expects natural gas to trade in a relatively low price range, which is unfavorable to most processors. Moreover, in some production basins, price-induced drilling reductions are expected to lower gathering volumes until demand recovers, an adverse trend for both processors and gatherers.

Retail Propane

2010 Outlook — Negative
Longer-Term Outlook— Negative

Fitch maintains a modestly negative short- and long-term outlook for the retail propane sector. Given propane's strong correlation to crude oil prices, Fitch remains concerned that retail propane prices could spike, particularly with a weak dollar, and margins could contract from current levels. Additionally, continued weakness in housing starts and a warmer winter could weigh on volumes sold. If sales volumes show a greater post-recession recovery and product margins hold up, the credit outlook would move toward stable.

For more information on the credit outlook for these businesses, please refer to Fitch's report, "Pipeline/Midstream/MLP 2010 Outlook," published on Dec. 3, 2009.

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Appendix: Ratings and Rating Outlooks by Segment

Utility Parent Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
WGL Holdings, Inc.	A+	Stable	A+
FPL Group, Inc.	A	Stable	A
NICOR Inc.	A	Stable	A
OGE Energy Corp.	A	Stable	A
Sempra Energy	A	Stable	A
Southern Company	A	Stable	A
AGL Resources, Inc.	A–	Stable	A–
DPL Inc.	A–	Stable	A–
KeySpan Corporation	A–	Stable	A–
Laclede Group, Inc.(The)	A–	Stable	**NR**
MDU Resources Group, Inc.	A–	Negative	A
National Fuel Gas Company	A–	Stable	A–
NSTAR	A–	Stable	A
Wisconsin Energy Corporation	A–	Negative	A–
Ameren Corporation	BBB+	Stable	BBB+
Consolidated Edison, Inc.	BBB+	Stable	BBB+
Dominion Resources, Inc.	BBB+	Stable	BBB+
Energy East Corporation	BBB+	Stable	**NR**
Exelon Corporation	BBB+	Stable	BBB+
MidAmerican Energy Holdings Co.	BBB+	Stable	BBB+
Public Service Enterprise Group Inc	BBB+	Stable	BBB+
SCANA Corporation	BBB+	Stable	BBB+
Xcel Energy Inc.	BBB+	Stable	BBB+
At Segment Median Rating			
American Electric Power Company	BBB	Stable	BBB
Black Hills Corp.	BBB	Stable	BBB
DTE Energy Company	BBB	Negative	BBB
FirstEnergy Corp.	BBB	Stable	BBB
IDACORP, Inc.	BBB	Negative	**NR**
Northeast Utilities	BBB	Stable	BBB
PEPCO Holdings	BBB	Negative	BBB
PPL Corporation	BBB	Stable	BBB
Progress Energy, Inc	BBB	Stable	BBB
Below Segment Median Rating			
Allegheny Energy, Inc.	BBB–	Stable	BBB–
Avista Corporation	BBB–	Stable	BBB
CenterPoint Energy Inc.	BBB–	Stable	BBB–
CILCORP, Inc.	BBB–	Stable	BBB–
Constellation Energy Group, Inc.	BBB–	Stable	BBB–
Edison International	BBB–	Stable	**NR**
IPALCO Enterprises, Inc.	BBB–	Stable	**BBB–**
NiSource Inc.	BBB–	Stable	BBB
Otter Tail Corporation	BBB–	Stable	BBB–
Pinnacle West Capital Corporation	BBB–	Negative	BBB–
TECO Energy, Inc.	BBB–	Stable	BBB–
CMS Energy Corporation	BB+	Stable	BB+
PSEG Energy Holdings, Inc.	BB+	Stable	BB
PNM Resources	BB	Stable	BB
NV Energy Inc.	BB–	Positive	BB–
Energy Future Holdings Corp.	B	Negative	B
Energy Future Intermediate Holding Company LLC	B	Negative	**B+**

NR – Not rated. Note: Bold indicates senior secured.
Source: Fitch.

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Investor-Owned Electric Utilities

Integrated Electric Utilities

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Mississippi Power Company	A+	Stable	AA–
Oklahoma Gas and Electric Company	A+	Stable	AA–
Alabama Power Company	A	Stable	A+
Dayton Power & Light Company	A	Stable	**AA–**
Florida Power and Light	A	Stable	A+
Georgia Power Company	A	Negative	A+
Wisconsin Electric Power Company	A	Negative	A+
Carolina Power & Light Co.	A–	Stable	A
Florida Power Corp.	A–	Stable	A
Gulf Power Company	A–	Stable	A
MidAmerican Energy Company	A–	Stable	A
Northern States Power Company (MN)	A–	Stable	A
Northern States Power Company (WI)	A–	Stable	A
Pacific Gas and Electric Company	A–	Stable	A
Southern California Edison Company	A–	Stable	A
AEP Texas North Company	BBB+	Stable	A–
Columbus Southern Power Company	BBB+	Stable	A–
Public Service Company of Colorado	BBB+	Stable	A–
South Carolina Electric & Gas Co.	BBB+	Stable	A–
Union Electric Co.	BBB+	Stable	A–
Virginia Electric and Power	BBB+	Stable	A–
At Segment Median Rating			
AEP Texas Central Company	BBB	Negative	BBB+
Black Hills Power, Inc.	BBB	Stable	BBB+
Central Illinois Light Company	BBB	Stable	BBB+
Detroit Edison Company (DECo)	BBB	Stable	**A–**
Idaho Power Company	BBB	Negative	BBB+
Ohio Power Company	BBB	Stable	BBB+
Otter Tail Power	BBB	Stable	BBB+
PacifiCorp	BBB	Stable	BBB+
Public Service Company of New Hampshire	BBB	Stable	**BBB+**
Public Service Company of Oklahoma	BBB	Stable	BBB+
Southwestern Electric Power Company	BBB	Negative	BBB+
Southwestern Public Service Company	BBB	Stable	BBB+
Tampa Electric Company	BBB	Stable	BBB+
Below Segment Median Rating			
Appalachian Power Company	BBB–	Stable	BBB
Arizona Public Service Company	BBB–	Stable	BBB
Consumers Energy Company	BBB–	Stable	BBB
Empire District Electric Company	BBB–	Negative	BBB
Indiana Michigan Power Company	BBB–	Stable	BBB
Indianapolis Power & Light Company	BBB–	Stable	BBB
Kansas Gas and Electric Company	BBB–	Stable	**BBB+**
Kentucky Power Company	BBB–	Stable	BBB
Monongahela Power Company	BBB–	Stable	BBB–
Northern Indiana Public Service Co.	BBB–	Stable	BBB
Northwestern Corporation	BBB–	Stable	BBB
Westar Energy, Inc.	BBB–	Stable	BBB
Nevada Power Company d/b/a NV Energy	BB	Positive	BB
Public Service Company of New Mexico	BB	Stable	BB+
Sierra Pacific Power Company d/b/a NV Energy	BB	Positive	**BBB–**
Tucson Electric Power Company	BB	Positive	BB+

Note: Bold indicates senior secured. *Continued on next page.*
Source: Fitch.

Investor-Owned Electric Utilities (Continued)

Electric Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
NSTAR Electric Co.	A+	Stable	AA–
San Diego Gas & Electric Company	A+	Stable	AA–
American Transmission Company	A	Stable	A+
Central Hudson Gas & Electric Corp	A–	Stable	A
Orange and Rockland Utilities, Inc.	A–	Negative	A
Rockland Electric Co.	A–	Negative	**NR**
Consolidated Edison Co. of New York	BBB+	Stable	A–
Delmarva Power & Light	BBB+	Stable	A–
PECO Energy Company	BBB+	Stable	**A**
Potomac Electric Power Company	BBB+	Stable	A–
Public Service Electric and Gas Co.	BBB+	Stable	**A**
At Segment Median Rating			
Atlantic City Electric	BBB	Stable	BBB+
Baltimore Gas and Electric Company	BBB	Stable	BBB+
CenterPoint Energy Houston Electric, LLC	BBB	Stable	BBB+
Connecticut Light and Power Co.	BBB	Stable	BBB+
Jersey Central Power & Light Co.	BBB	Stable	BBB+
New York State Electric & Gas Corp	BBB	Negative	BBB+
PPL Electric Utilities Corporation	BBB	Stable	**A–**
Western Massachusetts Electric Co.	BBB	Stable	BBB+
Below Segment Median Rating			
Central Illinois Public Service Co.	BBB–	Stable	BBB
Illinois Power Company	BBB–	Stable	BBB
Metropolitan Edison Company	BBB–	Stable	BBB
Ohio Edison Company	BBB–	Stable	BBB
Oncor Electric Delivery Company	BBB–	Stable	BBB–
Pennsylvania Electric Company	BBB–	Stable	BBB
Pennsylvania Power Company	BBB–	Stable	BBB
Potomac Edison Company (The)	BBB–	Stable	**BBB+**
Rochester Gas and Electric Corp	BBB–	Stable	BBB
West Penn Power Company	BBB–	Stable	BBB–
Cleveland Electric Illuminating Co.	BB+	Stable	BBB–
Commonwealth Edison Company	BB+	Stable	BBB–
Texas New Mexico Power Company	BB+	Stable	BBB–
Toledo Edison Company	BB+	Stable	BBB–

NR – Not rated. Note: Bold indicates senior secured.
Source: Fitch.

Competitive Generation Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
AmerenEnergy Generating Company	BBB+	Negative	BBB+
Exelon Generation Company, LLC	BBB+	Stable	BBB+
PSEG Power, LLC	BBB+	Stable	BBB+
Southern Power Company	BBB+	Stable	BBB+
FirstEnergy Solutions Corp. (FES)	BBB	Stable	BBB
PPL Energy Supply	BBB	Stable	BBB+
Allegheny Energy Supply Company	BBB–	Stable	BBB–
Allegheny Generating Company	BBB–	Stable	BBB–
Brookfield Renewable Power, Inc.	BBB–	Negative	BBB
Midwest Generation, LLC	BB	RWN	**BBB–**
At Segment Median Rating			
Edison Mission Energy	BB–	RWN	BB–
Mission Energy Holding Co.	BB–	Stable	**BB–**
Below Segment Median Rating			
AES Corporation	B+	Stable	BB
Mirant Americas Generation, LLC	B+	Stable	B
Mirant Corporation	B+	Stable	**NR**
Mirant Mid-Atlantic, LLC	B+	Stable	BB+
Mirant North America, LLC	B+	Stable	BB–
NRG Energy, Inc.	B	RWE	B+
Reliant Energy Inc	B	Negative	B+
Texas Competitive Electric Holdings	B	Negative	B
Dynegy Holdings, Inc.	B–	Negative	B
Dynegy, Inc.	B–	Negative	**NR**

NR – Not rated. RWN – Rating Watch Negative. RWE – Rating Watch Evolving. Note: Bold indicates senior secured.
Source: Fitch.

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Pipeline and Midstream Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Northern Natural Gas Co.	A	Stable	A
Centennial Energy Holdings, Inc.	A–	Negative	A–
LOOP LLC	A–	Stable	A–
EQT Corporation	BBB+	Stable	BBB+
Texas Eastern Transmission, LP	BBB+	Stable	BBB+
Texas Gas Transmission, LLC	BBB+	Stable	BBB+
Boardwalk Pipelines, LLC	BBB	Stable	BBB
CenterPoint Energy Resources Corp.	BBB	Stable	BBB
DCP Midstream LLC	BBB	Stable	BBB
Enogex Inc.	BBB	Stable	BBB
Kinder Morgan Energy Partners, L.P.	BBB	Stable	BBB
Northwest Pipeline Corporation	BBB	Stable	BBB
Rockies Express Pipeline LLC	BBB	Stable	BBB
Transcontinental Gas Pipe Line Corp	BBB	Stable	BBB
At Segment Median Rating			
Colorado Interstate Gas Co.	BBB–	Stable	BBB–
El Paso Natural Gas Co.	BBB–	Stable	BBB–
Energy Transfer Partners, L.P.	BBB–	Stable	BBB–
Enterprise Products Operating, LLC.	BBB–	Stable	BBB–
NGPL PipeCo LLC	BBB–	Stable	BBB–
NPOP (Kaneb Pipe Line Operating Partnership, L.P.)	BBB–	Stable	BBB–
NuStar Logistics, L.P.	BBB–	Stable	BBB–
Panhandle Eastern Pipeline Co.	BBB–	Stable	BBB–
Southern Natural Gas Co.	BBB–	Stable	BBB–
Southern Union Company	BBB–	Stable	BBB–
Tennessee Gas Pipeline Co.	BBB–	Stable	BBB–
TEPPCO Partners L.P.	BBB–	Stable	BBB–
Williams Companies, Inc.	BBB–	Stable	BBB–
Below Segment Median Rating			
AmeriGas Partners, L.P.	BB+	Stable	BB+
El Paso Corp.	BB+	Stable	BB+
El Paso Exploration & Production Co.	BB+	Stable	BB
Kinder Morgan Inc.	BB+	Stable	**BB+**
Williams Partners, LP	BB	Stable	BB
Energy Transfer Equity, L.P.	BB–	Stable	**BB**
Enterprise GP Holdings L.P.	BB–	Stable	**BB**
Star Gas Partners L.P.	B	Stable	BB–

Note: Bold indicates senior secured.
Source: Fitch.

Natural Gas Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Southern California Gas Company	A+	Stable	AA–
Washington Gas Light Company	A+	Stable	AA–
Brooklyn Union Gas Co.	A	Stable	A+
Nicor Gas Company	A	Stable	A+
Wisconsin Gas Company, LLC	A	Stable	A+
At Segment Median Rating			
Atlanta Gas Light Co.	A–	Stable	A
Cascade Natural Gas Corporation	A–	Negative	A
KeySpan Gas East Corporation	A–	Stable	A
Laclede Gas Company	A–	Stable	**A+**
NSTAR Gas	A–	Stable	**A**
UGI Utilities, Inc.	A–	Stable	A
Below Segment Median Rating			
Berkshire Gas Company	BBB+	Stable	A–
Central Maine Power Company	BBB+	Stable	A–
Connecticut Natural Gas	BBB+	Stable	A–
Public Service Company of North Carolina	BBB+	Stable	A–
Atmos Energy Corporation	BBB	Stable	BBB+
Southern Connecticut Gas	BBB	Negative	**A–**
Southwest Gas Corporation	BBB	Stable	BBB
Michigan Consolidated Gas Company	BBB–	Stable	**BBB+**
Mountaineer Gas Company	BB–	Stable	BB

Note: Bold indicates senior secured.
Source: Fitch.

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Public Power Companies — Retail Segment

Company Name	Rating Outlook	Senior Unsecured Rating
Above Median (A+)		
Chelan County Public Utility District No. 1 (Wash.)	Stable	AA+
San Antonio (Texas) (CPS Energy)	Stable	AA+
Chattanooga — Electric Power Board (Tenn.)	Stable	AA
Colorado Springs Utilities	Stable	AA
Grant County Public Utility District No. 2 (Wash.) — Electric System	Stable	AA
Lincoln (Neb.) — Electric System	Stable	AA
Memphis (Tenn.) — Memphis Light, Gas & Water	Stable	AA
Nashville (Tenn.) — Electric System	Stable	AA
Omaha Public Power District (Neb.)	Stable	AA
Orlando Utilities Commission (Fla.)	Stable	AA
Springfield (Mo.) — City Utilities (Electric)	Stable	AA
St. Cloud (Fla.) — Utility System	Stable	AA
Anaheim Public Utilities Department (Calif.)	Negative	AA–
Austin Combined Utility System (Texas)	Stable	AA–
Austin Energy (Texas)	Stable	AA–
Concord (N.C.) Utilities System	Stable	AA–
Hydro-Quebec	Stable	AA–
JEA (Fla.) — Electric	Stable	AA–
Los Angeles Department of Water and Power (Calif.)	Stable	AA–
New Braunfels Utilities (Texas)	Stable	AA–
Pasadena (Calif.) — Water and Power Department	Stable	AA–
Richmond (Va.)	Stable	AA–
Riverside Public Utilities (Calif.)	Stable	AA–
Rochester Public Utilities (Minn.)	Stable	AA–
Snohomish County Public Utility District No. 1 (Wash.)	Stable	AA–
Tallahassee (Fla.) — Energy System	Stable	AA–
At Median (A+)		
Anchorage Municipal Light & Power (Alaska)	Stable	A+
Bryan, Texas Utilities	Stable	A+
California Department of Water Resources	Positive	A+
Dover (Del.)	Stable	A+
Eugene Water and Electric Board (Ore.)	Stable	A+
Farmington (N.M.) Utility System	Stable	A+
Garland Power & Light (Texas)	Stable	A+
Glendale (Calif.) — Water and Power	Stable	A+
Georgetown (Texas)	Stable	A+
Greer (S.C.) — Commission of Public Works	Stable	A+
Imperial Irrigation District (Calif.)	RWN	A+
Jacksonville Beach (Fla.) — Combined Utility System	Stable	A+
Kansas City (Kan.) — Board of Public Utilities	Stable	A+
Kerrville Public Utility Board (Texas)	Stable	A+
Lakeland Energy System (Fla.)	Stable	A+
Muscatine Power & Water (Iowa)	Stable	A+
Ocala (Fla.)	Stable	A+
Pedernales Electric Cooperative, Inc. (Texas)	Stable	A+
Redding (Calif.)	Stable	A+
Roseville Electric System (Calif.)	Stable	A+
Tacoma Power (Wash.)	Stable	A+
Turlock Irrigation District (Calif.)	Stable	A+
Below Median (A+)		
Benton County Public Utility District No. 1 (Wash.)	Stable	A
Brownsville Public Utility Board (Texas)	Stable	A
Bryan, Rural Electric	Stable	A
Floresville (Texas) — Electric Light and Power System	Stable	A
Gallup (N.M.) — Utility System	Stable	A
Granbury (TX)	Negative	A
Grays Harbor County Public Utility District No. 1 (Wash.)	Stable	A
Kissimmee Utility Authority (Fla.)	Stable	A
Modesto Irrigation District (Calif.)	Stable	A

RWN – Rating Watch Negative. *Continued on next page.*
Source: Fitch.

Public Power Companies — Retail Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Below Median (A+) (Continued)		
Overton Power District No. 5 (NV)	Stable	A
Paducah (Kent.)	Stable	A
Reedy Creek Improvement District (Fla.)	Stable	A
Sacramento Municipal Utility District (Calif.)	Stable	A
Silicon Valley Power (Calif.)	Stable	A
Vero Beach (Fla.)	Stable	A
Winter Park (Fla.)	Negative	A
Alameda Power & Telecom (Calif.)	Positive	A–
Batavia (Ill.) — Electric Utility	Stable	A–
Boerne Utility System (Texas)	Stable	A–
Chugach Electric Association, Inc. (Alaska)	Stable	A–
Cowlitz CO Public Utility District	Stable	A–
Fort Pierce Utilities (Fla.)	Stable	A–
Klickitat County Public Utility District No. 1 (WA)	Stable	A–
Long Island Power Authority (N.Y.)	Negative	A–
Los Alamos County (N.M.) — Utility System	Stable	A–
Lubbock Power & Light (Texas)	Stable	A–
Pend Oreille County Public Utility District No. 1 (Wash.)	Stable	A–
Seguin (Texas)	Stable	A–
Leesburg (Fla.) — Electric System	Stable	BBB+
Lodi (Calif.) — Electric Utility	Positive	BBB+
Puerto Rico Electric Power Authority	Stable	BBB+
Virgin Islands Water & Power Authority	Negative	BBB
Vermont Electric Cooperative Inc.	Stable	BBB–
Guam Power Authority	Positive	BB+

Source: Fitch.

Public Power Companies — Wholesale Segment

Company Name	Rating Outlook	Senior Unsecured Rating
Above Median (A)		
Tennessee Valley Authority	Stable	AAA
Associated Electric Cooperative Inc. (MO)	Stable	AA
Energy Northwest (Wash) — Bonneville Power Agency	Positive	AA
Grant County Public Utility District No. 2 (Wash.) — Hydro Projects	Stable	AA
New York Power Authority	Stable	AA
Platte River Power Authority (Colo.)	Stable	AA
South Carolina Public Service Authority (Santee Cooper)	Stable	AA
Basin Electric Power Cooperative	Stable	AA–
Intermountain Power Agency (Utah)	Stable	AA–
Western Minnesota Municipal Power Agency	Stable	AA–
Arkansas Electric Cooperative Corp.	Stable	A+
Connecticut Municipal Electric Energy Cooperative	Stable	A+
Florida Municipal Power Authority — All Requirements Project	Stable	A+
Florida Municipal Power Authority — Stanton I	Stable	A+
Florida Municipal Power Authority — Stanton II	Stable	A+
Florida Municipal Power Authority — Tri-City Project	Stable	A+
Illinois Municipal Electric Agency	Stable	A+
Indiana Municipal Power Agency	Stable	A+
Lower Colorado River Authority (Texas)	Stable	A+
Municipal Electric Authority of Georgia (CC/CT Proj)	Stable	A+
Municipal Electric Authority of Georgia (General Res)	Stable	A+
Municipal Electric Authority of Georgia (Project One)	Stable	A+
Municipal Electric Authority of Georgia (Telecom)	Stable	A+
Nebraska Public Power District	Stable	A+
Walnut Energy Center Authority (Calif.)	Stable	A+
Wisconsin Public Power Inc.	Stable	A+
Buckeye Power, Inc (Ohio)	Stable	A+
At Median (A)		
American Municipal Power — Issuer Rating	Stable	A
American Municipal Power-Inc. — Joint Venture No. 5	Stable	A
American Municipal Power-Inc. — Prairie State Project	Stable	A
Berkshire Wind Power Cooperative Corporation (MA)	Stable	A
Brazos Electric Power Cooperative, Inc. (Texas)	Stable	A
Florida Municipal Power Authority — St. Lucie Project	Stable	A
Grand River Dam Authority (Okla.)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Nuclear Mix No. 1)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 3)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 4)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 5)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 6)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Stoney Brook Intermediate)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Wyman)	Stable	A
Missouri Joint Municipal Electric Utility Commission (Iatan 2 Project)	Stable	A
M-S-R Public Power Agency (Calif.)	Stable	A
Municipal Energy Agency of Nebraska	Stable	A
North Carolina Municipal Power Agency No. 1	Stable	A
Northern California Power Authority — Geothermal Project	Stable	A
Northern California Power Authority — Hydroelectric Project	Stable	A
Oglethorpe Power Co. (Ga.)	Stable	A
Oglethorpe Power Co. (Ga.) — Scherer Facilities	Stable	A
Old Dominion Electric Cooperative (Va.)	Stable	A
Texas Municipal Power Agency	Stable	A
Tri-State Generation & Transmission Association, Inc. (Colo.)	Stable	A
Below Median (A)		
American Municipal Power-Inc. — Joint Venture No. 2	Stable	A–
Central Iowa Power Cooperative	Stable	A–
Delaware Municipal Electric Cooperative	Stable	A–
Energy Northwest (Wash.) — Wind Project	Stable	A–
Golden Spread Electric Cooperative, Inc. (Texas)	Stable	A–
Great River Energy (MN)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Plum Point Project)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Prairie State Project)	Stable	A–
Northern Illinois Municipal Power Agency	Stable	A–
PowerSouth Energy Cooperative, Inc.	Stable	A–
South Texas Electric Cooperative	Stable	A–

Continued on next page.
Source: Fitch.

FitchRatings KNOW YOUR RISK

Corporates

Public Power Companies — Wholesale Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Wholesale Segment — Below Median (A) (Continued)		
Western Farmers Electric Cooperative (Okla.)	Negative	A–
Central Valley Financing Authority (Calif.)	Stable	BBB+
North Carolina Eastern Municipal Power Agency	Positive	BBB+
Piedmont Municipal Power Agency (S.C.)	Stable	BBB+
Sacramento Cogeneration Authority (Calif.) — P&G Project	Stable	BBB+
Sacramento Power Authority (Calif.) — Campbell Project	Stable	BBB+
Sacramento Municipal Utility District Financing Authority (Calif.) — Cosumnes Project	Stable	BBB
Big Rivers Electric Corporation (Kent.)	Stable	BBB–
Sam Rayburn Municipal Power Agency (Texas)	Stable	BBB–

Source: Fitch.

CREDIT AND CAPITAL ISSUES AFFECTING THE ELECTRIC POWER INDUSTRY

FERC TECHNICAL CONFERENCE

Garry Brown, Chairman, New York State Public Service Commission & Chairman, Committee on Electricity, National Association of Regulatory Utility Commissioners — January 13, 2009

Good afternoon and thank you for the opportunity to address this important conference. Today, I will be speaking to you as both Chairman of the New York State Public Service Commission and as Chairman of the NARUC Committee on Electricity.

As you may know, the New York Commission is responsible for setting rates and ensuring adequate electric service is provided by New York's utilities. The NARUC Committee's role is to develop and advance policies that promote reliable, adequate, and affordable supply of electricity. Through strong collaboration with the Federal Energy Regulatory Commission and related Federal agencies, the Committee also seeks ways to improve the quality and effectiveness of regulation through education, cooperation, and exchange of information.

We have just heard from a number of experts representing investors and various electric power industry participants. It is quite evident that there are many challenges facing the industry as a whole.

At the outset, I want to note that it is typically the responsibility of State utility regulators to assure that the state's electric utilities provided safe and reliable service at a reasonable price. This requires utilities to make investments, some of which are very substantial. Utilities generally desire certainty from regulators that they can recover their investments including a reasonable return.

With that said, it is important to recognize the economic realities of a recession and expect utilities to take a hard look at their capital programs with an eye toward prioritizing. This not only reduces utility exposure to the volatile financial markets but also helps to relieve upward pressure on rates to end-use customers caused by an increase in the utility asset investment base (rate base). For example, those projects that are essential to safety and reliability must go forward while those that are discretionary and can be deferred should be evaluated on a case by case basis as to whether customers are best served by going forward with the projects at this time.

I note that there are several potential drivers of utility investment on the horizon — transmission and distribution upgrades due to aging infrastructure and to meet new needs, requirements to create a smart grid, energy efficiency investments, renewable energy mandates, and, in some parts of the country, capital for new power plant construction. These potential investments will require billions of dollars to support.

Large capital programs such as the ones noted make it very important that electric utilities continue to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital.

Speaking parochially from a New York perspective our policies over the years, while not always viewed by some as investor-friendly, have nonetheless resulted in no New York electric utility currently being rated less than BBB+ (Con Edison, Orange & Rockland, Central Hudson, are in the A category while NYSEG and Rochester Gas & Electric are BBB+).

In the last two months, New York electric utilities have raised about $800 million in the markets — ($600 million for Con Edison, $150 million for Rochester Gas & Electric, and about $50 million for Central Hudson.) Thus, our utilities have been able to raise capital even in these difficult financial times. That said, however, the interest costs associated with new utility debt issues has been extremely high relative to yields on comparable treasury securities.

I should note that there is a clear relationship between a utility's bond rating and its ability to borrow at a reasonable cost, especially in times of economic distress as we are now facing.

For example, in New York, we have, for many years, considered the question of what the most cost effective electric utility bond rating is for ratepayers. While the Commission has never formally stated a particular policy, I think most experts would say that over the last 15 years the answer probably was some place in the BBB-A range, depending on the assumptions employed in the analysis. While this may be a good answer over the long run, it flies in the face of current reality.

Given current economic realities, 100-200 basis point premiums on the yield for BBB debt over A debt may indicate that A is cheaper to ratepayers now. The policy question for utilities and regulators to grapple with is how long the current situation will continue and how often we can expect similar situations in the future.

While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment grade securities. To me this suggests that you do not want to be rated at the lower end of the BBB range because an unexpected shock could move you outside the investment grade range.

Now turning to implications of the current financial environment on market players, I think you will hear from the Short-Term Electricity Markets panel shortly concerns regarding the need to tighten up credit requirements to reduce the risk of default in the markets.

For example, in New York, the rules for extending credit by NYISO are largely based on lagging data, such as ratings and prior financial statements that may not adequately capture the potential for the type of rapid financial deterioration that we've been seeing. While the cost of market defaults will ultimately be paid by consumers, the costs of potential remedies to avoid defaults, such as reducing load-serving entities unsecured credit lines or requiring accelerated cash payments, will also be born by consumers. It is therefore incumbent upon both State and Federal regulators to ensure that these rules provide balance and that the entities that administer these markets have the tools and ability to react quickly to changing conditions.

Anecdotally, we have heard that the current environment is leading to difficulties in raising capital for investors in certain renewable projects. Many states have RPS goals in place. Some of the projects rely partly on state and federal funding. If the current financial situation continues to persist, there may be an impact on the achievement of RPS goals. Regulators may need to consider how their funding for renewables should be changed to help achieve RPS goals.

Clearly, we are in uncharted waters. There remains a significant concern that some might try to use this opportunity to achieve other goals. We need to be diligent to ensure that what actions we might take today are indeed the best decision to ensure the safety and reliability of the electric power industry.

We regulators need to ask tough, pointed questions. We need to be watchful. Asking questions does not mean we are not supportive; it means we as regulators must continue to recognize that our primary responsibility is to ensure safety and reliability at just and reasonable rates.

MOODY'S INVESTORS SERVICE

CREDIT OPINION
21 September 2022

Update

Send Your Feedback

RATINGS

American Electric Power Company, Inc.

Domicile	Columbus, Ohio, United States
Long Term Rating	Baa2
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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American Electric Power Company, Inc.

Update to credit analysis

Summary

American Electric Power Company's (AEP) credit profile is underpinned by the size and diversity of its regulatory jurisdictions and service territories. AEP's nine retail utility subsidiaries operate under eleven different state regulatory bodies and its transmission subsidiaries are regulated by the Federal Energy Regulatory Commission (FERC). The company's credit profile is supported by a corporate strategy of focusing on its core regulated utility assets with predictable earnings, with its most significant growth area being its transmission and distribution (T&D) utilities. For the twelve months ending 30 June 2022, we estimate that these less volatile T&D businesses contributed approximately 46% of AEP's consolidated operating income.

Since 2018, AEP's cash flow has been negatively impacted by the accelerated return of deferred income taxes, and the company's reliance on debt financing at the parent level to fund the group's elevated capital investment program. AEP's 2021 credit metrics were unusually weak because of the impact of severe winter weather in some of its service territories. We expect the company's ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to be sustained in a range of 13-15%, and parent level debt to remain under 25% of consolidated debt over the next two years.

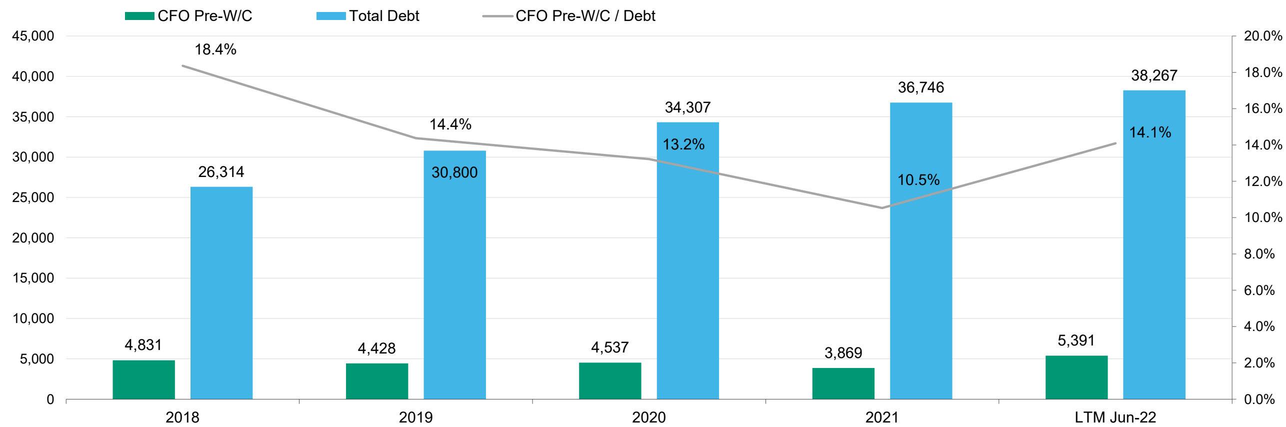
Recent developments

Planned sale of unregulated renewables assets - In February 2022, AEP announced a process to sell some or all of its competitive contracted renewables assets. A sale of these assets would increase the proportion of AEP's cash flow that comes from its regulated operations, a credit positive. However, given the small contribution of these assets (around 2% of funds from operations), a sale of all the assets would not change our current view of AEP's credit quality as a substantially fully regulated utility holding company.

Pending sale of Kentucky Operations - In October 2021, AEP agreed to sell its operations in Kentucky to Liberty Utilities Co., a subsidiary Algonquin Power and Utilities Corp (not rated) for an enterprise value of approximately $2.8 billion, including about $1.3 billion of estimated debt at closing. The transaction is credit neutral given the small size of the Kentucky companies and the expected use of substantially all of the cash proceeds to replace $1.4 billion of AEP's planned equity financing. The sale has received required state regulatory approvals and will close following regulatory approval from the FERC, which we expect before the end of 2022.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



Source: Moody's Financial Metrics

Credit strengths

» Scale and diversity of regulatory jurisdictions and service territories provide a strong foundation for current credit profile

» Good cost recovery via trackers and riders

» Bulk of spending is for transmission and distribution investments

Credit challenges

» A number of unfavorable recent regulatory outcomes

» Substantial capital expenditures

» Debt financed investments will continue to pressure credit metrics

Rating outlook

The stable outlook recognizes that AEP continues to benefit from mostly supportive regulatory frameworks that provide numerous riders and trackers to assure the recovery of investments. The outlook considers that the sizable capital programs are focused on lower risk transmission and distribution networks and renewables, facilitating the organization's clean energy transition and reducing its carbon transition risk. The outlook assumes that the company will maintain generally supportive regulatory relationships across its jurisdictions and that it will stabilize the long-term decline in credit metrics and generate a consolidated ratio of CFO pre-WC to debt in the range of 13-15%.

Factors that could lead to an upgrade

» A reduction in leverage, or changes to the company's capital or operating plans that lead to an increase in cash flow and a ratio of CFO pre-WC to debt consistently above 15% could put upward pressure on the rating.

» A reduction in parent leverage, for example a ratio of parent level debt to consolidated debt closer to 10%, could also put upward pressure on the rating.

Factors that could lead to a downgrade

» AEP's rating could be downgraded if a more contentious regulatory environment were to develop in any of its key jurisdictions, if ongoing capital investments cannot be recovered on a timely basis, or if financial metrics deteriorate such that its ratio of CFO pre-WC to debt is maintained below 13%.

Key indicators

Exhibit 2

American Electric Power Company, Inc. [1]

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
CFO Pre-W/C + Interest / Interest	5.4x	4.7x	4.6x	4.2x	5.3x
CFO Pre-W/C / Debt	18.4%	14.4%	13.2%	10.5%	14.1%
CFO Pre-W/C – Dividends / Debt	13.6%	10.0%	9.0%	6.4%	9.9%
Debt / Capitalization	50.3%	52.8%	53.8%	54.0%	53.5%

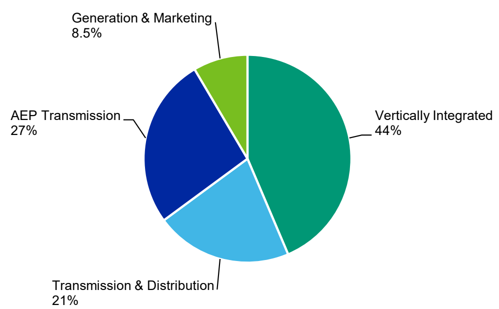
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in Columbus, Ohio, AEP is a large electric utility holding company with nine vertically integrated or retail transmission and distribution utility subsidiaries operating in eleven states. The company also operates transmission companies within the eastern and southwestern regions of the United States and owns a competitive generation and marketing business that is currently focused on growing its contracted renewable generation portfolio. AEP has a regulated rate base of around $56 billion and serves about 5.5 million customers. In 2021, the net maximum capacity of the company's owned and leased generation assets totaled approximately 24,862 MW, of which about 48% was coal/lignite fired.

Exhibit 3

Percentage breakdown of earnings attributable to AEP common shareholders



As of December 31, 2021
Source: Company filings

Detailed credit considerations

Scale and diversity of regulatory jurisdictions and service territories provides a strong foundation supporting current credit profile

AEP's size and diversity in terms of regulatory jurisdictions and service territory economies is a meaningful credit strength as it provides the company with a degree of insulation from any unexpected negative developments occurring at any one of its operating companies, state regulatory bodies or local economies. This diversity has been helpful in managing weak demand growth and adverse weather events in some of AEP's service territories as the company spends heavily on system reliability and to reduce its carbon footprint. Going forward, the largest portion of AEP's capital program will be for investment in its federally regulated transmission subsidiaries along with increased investment in transmission and distribution operations and clean energy at its state regulated utility subsidiaries.

AEP's primary state regulated utilities and their respective authorities are as follows:

» Appalachian Power Company (APCo: Baa1 stable), which accounted for approximately 15% of AEP's consolidated operating income for the twelve months ending 30 June 2022, operates under the Virginia State Corporation Commission (VSCC), (covering a little over half of APCo's customers) and the Public Service Commission of West Virginia (WVPSC)

» AEP Texas (AEP Texas: Baa2 stable), about 14% of AEP's consolidated operating income, regulated by the Public Utility Commission of Texas (PUCT)

» Ohio Power Company (OPCo: Baa1 stable), about 11% of AEP's consolidated operating income, operates under the Public Utility Commission of Ohio (PUCO)

» Indiana Michigan Power Company (I&M: A3 stable), about 10% of AEP's consolidated operating income, regulated by the Indiana Utility Regulatory Commission (IURC), (about ¾ of I&M's customers) and the Michigan Public Service Commission (MPSC)

» Southwestern Electric Power Company (SWEPCo: Baa2 stable), about 9% of AEP's consolidated operating income, operates under the Louisiana Public Service Commission (LPSC) (about 43% of SWEPCo retail customers), the Arkansas Public Service Commission (ARPSC) (22% of SWEPCo retail customers) and the PUCT (35% of SWEPCo retail customers)

» Public Service Company of Oklahoma (PSO: Baa1 stable), about 5% of AEP's consolidated operating income, regulated by the Oklahoma Corporation Commission (OCC); and

» Kentucky Power Company (KPCo: Baa3 stable), about 2% of AEP's consolidated operating income, regulated by the Kentucky Public Service Commission (KPSC). A currently pending sale of KPCo to Liberty Utilities Co. is expected to close by the end of 2022.

AEP Transmission Company LLC's (AEP Transco: A2 stable) transmission businesses, which accounted for the largest portion (about 21%) of AEP's consolidated operating income as of 30 June 2022, are regulated by the FERC under forward looking formulaic rate plans that result in a high degree of cash flow predictability. Operations are conducted through six subsidiaries within AEP's electric utility service territories in seven states: Ohio, West Virginia, Kentucky, Oklahoma, Tennessee, Indiana and Michigan.

Exhibit 4
Regulated rate base by subsidiary as of 31 December 2021
($ in millions)

Source: Company presentations

Continued regulatory support with timely and sufficient cost recovery important to credit quality

Given the significant amount of capital expenditures (capex) AEP has planned across its regulated businesses, it is essential that the company maintain a supportive relationship with its regulators to sustain credit quality. Our view of AEP's credit quality reflects our assumption that the company's will generally continue to receive timely and consistent long-term regulatory support across the majority of its subsidiary utility jurisdictions. Recent regulatory filings, orders and updates for AEP subsidiaries are as follows:

AEP Transco – The AEP Transco subsidiaries receive revenues based on FERC approved formulaic tariffs that are set to allow the recovery of all expenditures for operations, maintenance, depreciation and taxes plus a return on forward looking capital investments. The AEP Transco companies operate in the PJM Interconnection (PJM) (about 85%) and the Southwest Power Pool (SPP).

In April 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (NOPR) proposing to limit its incentive for transmission owners that join a Regional Transmission Organization (RTO) to three years. The supplemental NOPR was subject to a 60 day comment period followed by a 30 day period for reply comments. AEP submitted reply comments in July 2021. A final rule from the FERC is pending.

APCo (Virginia) – The VSCC has historically provided reasonable regulatory support to APCo, although the company's most recent rate case has been contentious, with the utility appealing the VSCC's regulatory determinations to the Virginia Supreme Court. The company benefits from numerous riders and trackers that serve to assure recovery and reduce regulatory lag for specific expenditures, including those for new generating assets, environmental expenditures, energy efficiency expenditures, and investments in renewables and transmission assets. Recovery of legacy generation assets, and distribution operations, are covered during the state's periodic earnings review process. Legislation passed in 2018 revised the review period to triennial and required APCo to file a rate case by March of 2020.

In November 2020, the VSCC determined that APCo's earned ROE was 9.48%, which is within the upper half of the specified range of 8.72% - 10.12% for the review period and thus no rate increase was granted. The VSCC's decision incorporated staff's proposed treatment of APCo's retired coal plants, which reversed APCo's 2019 expense and instead amortized the retired assets over ten years beginning in 2015 (the year they were closed). In addition, the VSCC lowered APCo's authorized ROE to 9.2%.

APCo had requested a $65 million increase based on a 9.9% ROE and, in accordance with its interpretation of state law, had recorded a $93 million expense related to its retired coal plants. Including this expense, APCo calculated its Virginia earnings during the review period to be only 8.24%. In March 2021, the VSCC rejected requests for reconsideration from APCo and an intervenor. APCo filed an appeal with the Virginia Supreme Court in March 2021. In August 2022, the Supreme Court ruled in favor of APCo and remanded the case back to the VSCC. The VSCC ordered APCo to file no later than 23 September 2022 for base interim rates effective 1 October 2022 and a rider for revenues not collected from 1 January 2021 through 30 September 22. Interim rates will be subject to review and potential refund.

APCo (West Virginia) – Moody's has historically viewed West Virginia's regulatory environment under the WVPSC as below average with respect to its long-term credit support, characterized by recovery lag and returns that were below the national average. However, more recent developments have been positive for APCo and its affiliate Wheeling Power Company (WPCo), who file on a joint basis.

APCo's most recent base rate case was finalized in February 2019 when the WVPSC approved a settlement agreement filed by APCo and WPCo that increased rates by $44 million ($36 million related to APCo), or 3% based on a 9.75% ROE.

In June 2021, the WVPSC approved an investment tracker surcharge mechanism proposed by APCo and WPCo to recover costs associated with capital investments made between base rate cases, a credit positive. An initial annual revenue requirement of $44 million ($36 million related to APCo), effective September 2021, was approved based on a 9.25% ROE. The order allows APCo and WPCo to request future year investment tracker increases for assets placed in service during the most recent 12-month period ending 30 September. Increases are subject to an annual three percent rider increase cap on base year total retail revenues. The order prohibits APCo and WPCo from filing a base rate case before 30 June 2024.

AEP Texas – We view the PUCT's regulation of transmission and distribution utilities in Texas as transparent and generally supportive of credit quality. Rider mechanisms for the recovery of investments in transmission and distribution systems significantly reduce regulatory lag and result in predictable cash flow. AEP Texas' investments in its systems are able to be recovered quickly through transmission cost of service (TCOS) and distribution cost recovery factor (DCRF) rider adjustment mechanisms. Certain expenses, for example those relating to energy efficiency, are also recovered via automatic adjustments. Revenues generated under these mechanisms do, however, remain subject to review. Notwithstanding these credit supportive regulatory mechanisms, AEP Texas' 2020 rate case outcome was unfavorable.

In AEP Texas' first consolidated rate case proceeding since its predecessors AEP Texas Central and AEP Texas North completed their last rate cases in 2007, the PUCT in April 2020, approved a settlement agreement that resulted in a $40 million base rate reduction premised on a 9.4% ROE and a 42.5% equity layer. The April 2020 order also included several adjustments in year one relating to the return of excess deferred taxes to transmission and distribution customers (totaling about $108 million) and for previously collected rates subject to reconciliation ($30 million) which resulted in a first year revenue reduction of over $170 million.

While the AEP Texas territory was impacted by the February 2021 winter storm, the regulatory construct for transmission and distribution utilities in Texas significantly limits the potential financial impact. These utilities do not procure power for customers and, unlike their counterparts in other deregulated markets, are not obligated to provide standard supply or provider of last resort service.

SWEPCo – The utility's retail operations are spread across three states, Louisiana, Texas and Arkansas, and the company also supplies energy to wholesale customers under FERC regulated contracts with formulaic rates. We view these jurisdictions as relatively credit supportive. In addition to its FERC contracts, SWEPCo currently benefits from formulaic rate processes in Louisiana and Arkansas; in Texas, the company benefits from rider recovery on the transmission and distribution portion of its rates.

SWEPCo was impacted by severe winter weather in February 2021. Consequently, as of 30 June 2022, SWEPCo has deferred a regulatory asset of about $375 million for fuel and purchased power costs incurred between 9 February and 20 February 2021. Of these costs, $95 million, $134 million and $146 million are related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

Texas - In January 2022, the PUCT approved an annual revenue increase of $39 million based upon a 9.25% ROE after SWEPCo had requested a $100 million rate increase based on a 10.35% ROE. SWEPCo also requested recovery of the $45 million Texas jurisdictional share of the Dolet Hills Power Station (Dolet Hills) which was retired in December 2021. The PUCT order authorized recovery of the remaining net book value of Dolet Hills beginning in 2022 through 2046. The order denied a return on the remaining book value and, as a result, SWEPCo recorded a disallowance of $12 million. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging several items in the order including the approved ROE and the denial of a reasonable return or carrying costs on Dolet Hills.

In March 2022, the PUCT ordered SWEPCo to recover the Texas jurisdictional share of the extraordinary February 2021 fuel costs over five years with a carrying charge of 1.65%.

Louisiana - In December 2020, SWEPCo filed for a $134 million rate increase in Louisiana, based on a 10.35% ROE and equity later of 50.8%. The requested rate increase was subsequently lowered to $95 million to reflect the removal of storm restoration costs that have been requested in a separate storm filing, and modifications to proposed Dolet Hills recovery and other proposed amortizations. The filing requests an extension of the formula rate plan for five years with certain modifications and includes annual depreciation increases to recover Louisiana's share of the Pirkey and Welsh power plants. Settlement discussions are ongoing.

In April 2021, SWEPCo began recovery of its Louisiana jurisdictional share of extraordinary February 2021 fuel costs based on a five year recovery period. However, the utility will work with the LPSC in future proceedings to determine the actual recovery period and an appropriate carrying charge.

Arkansas - In July 2021, SWEPCo, filed for an $85 million rate increase in Arkansas (later lowered to $81 million) based on a 10.35% ROE and 51.3% equity layer. The filing also provides notice of reelection for rate regulation under their formulaic rate mechanism. In May 2022, the APSC approved a revenue increase of $49 million based on a 9.5% ROE and a 45% equity layer. The order included approval to recover the Arkansas share of Dolet Hills as a regulatory asset over five years without a return. The order also denied accelerated depreciation for the Pirkey Plant and Welsh Plant, Units 1 and 3 and approved a rider to recover SPP costs and revenues. Rates became effective in July 2022. In July 2022, the ASPC denied a motion for rehearing filed by SWEPCo in June 2022 to challenge the approved capital structure.

In June 2022, SWEPCo was authorized to recover the Arkansas jurisdictional share of the extraordinary February 2021 fuel costs over six years with a carrying charge equal to its weighted average cost of capital, subject to a prudency review and true-up.

OPCo – The PUCO has historically demonstrated a credit supportive view for utilities operating in the state of Ohio. For several years, utilities have been operating under individually tailored electric security plans (ESPs), which are rate plans for the supply and pricing of electric generation service. The ESPs also incorporated numerous riders and trackers to support utility financial health as the state transitioned to competitive markets. OPCo's current ESP was approved in April 2018 and runs through May of 2024.

In March 2021, OPCo filed a settlement agreement on its distribution rate case that calls for a $295 million annual revenue increase incorporating a 9.7% ROE and a 54% equity layer. The case was initiated in May 2020, when OPCo requested an annual base rate revenue increase of approximately $400 million, premised on a 10.15% ROE and 54% equity layer inclusive of amounts currently being recovered in riders. Excluding costs reflected in riders, the settlement represents a $68 million reduction in base rates and includes the removal of proposed future energy efficiency costs and a decrease in vegetation management expenses moved to recovery in riders. The settlement also includes a higher fixed monthly residential customer charge and continues the utility's distribution investment rider with annual revenue caps. The revenue caps are subject to increase if the utility achieves certain reliability standards. As part of the settlement, OPCo's rate decoupling mechanism was discontinued, a credit negative. In November 2021, the PUCO approved the settlement and rates became effective December 2021.

I&M (Indiana) – I&M continues to benefit from rider recovery for its ongoing investment in the Cook nuclear life cycle management project, and the use of forward test years for base rate case proceedings.

In July 2021, I&M filed a multi-step electric base rate increase request with the IURC. The request includes a net revenue increase of $97 million incorporating a 10.0% ROE and approximately 51% equity layer. In November 2021, a joint settlement agreement was filed for a $61 million annual revenue increase based on a 9.7% ROE. The joint settlement was approved by the IURC in February 2022. A $3 million annual increase became effective February 2022 with the remaining $58 million becoming effective in January 2023.

The differences in the final decision and the original request are driven by changes in I&M's capital structure, decreased depreciation rates and the removal of Rockport Plant, Unit 2 from base rates. Plant costs will be recovered through riders until the expiration of the current lease in December 2022, in conjunction with the closing of I&M's and AEP Generating Company's agreement to acquire 100% of the interests in the plant from financial institutions that currently own it. The acquisition gives AEP the control to ensure the plant's retirement by 2028.

I&M (Michigan) – Michigan also allows the use of forward test years for the setting of base rates, and cases must be decided in ten months. In January 2020, the MPSC approved a settlement agreement implementing a $36 million base rate increase based on a 9.86% ROE.

PSO – To date, the OCC has not approved PSO's request to accelerate the depreciation of some of its coal-fired assets and their required environmental investments, a credit negative. In PSO's 2019 rate case decision, the OCC denied the company's request to increase the amount of depreciation collected in rates to fully recover the cost of the Oklaunion Power Station (closed in 2020) by 2028 as opposed to its current 2046 schedule. PSO's investment in the coal-fired Northeastern Unit 3, to be retired in 2026, and its related environmental control equipment is currently being recovered through 2040. The company's 2021 base rate request included $57 million associated with the accelerated depreciation recovery of Oklaunion and Northeastern Unit 3 power plants through 2026.

In April 2021, PSO filed an electric base rate case with the OCC requesting a net annual revenue increase of $172 million based upon a 10% ROE. PSO also requested the continuation of its transmission cost tracker and the continuation and expansion of the distribution and safety reliability rider to recover projects in a proposed grid transformation and revitalization plan which includes $100 million of annual capital spend over a 5 year period.

In September 2021, PSO, the OCC staff and other intervenors filed a settlement that included a $51 million net annual revenue increase based upon a 9.4% ROE. The settlement included recovery of the Oklaunion Power Station regulatory asset through 2046 with a debt return and continued recovery of Northeastern Unit 3 through 2040, as well as updated depreciation rates for plant in service (excluding coal production plant). Interim rates were established in November 2021 based on the $51 million increase. The OCC approved the agreement in December 2021. Interim rates were terminated and updated rates in accordance with the final order became effective February 2022.

PSO was significantly impacted by severe winter weather in February 2021. As of 30 June 2022, PSO has deferred a regulatory asset of about $684 million for fuel and purchased power costs incurred between 9 February and 20 February 2021. In April 2021, legislation was enacted in Oklahoma to securitize the February 2021 fuel and purchased power costs, a credit positive. In February 2022, the OCC approved the securitization of the unrecovered fuel and purchased power costs in a financing order. The securitization was approved by the Oklahoma Supreme Court in May 2022 and PSO issued the bonds in September 2022.

KPCo – KPCo benefits from a suite of cost recovery mechanisms that help reduce regulatory lag, including a fuel adjustment clause, rider recovery for certain PJM transmission costs, and environmental recovery riders which enable utilities in the state to earn a return on construction work in progress. Despite these positive factors, the KPSC's recent decisions have been impacted by the weak economic conditions in KPCo's service territory and have been less supportive of utility credit quality.

In January 2021, the KPSC authorized a $52.4 (later modified to $52.7) million base rate increase premised on a 9.3% return on equity (ROE). The case was initiated in June of 2020 when KPCo filed a request for a $65 million increase in base rates premised on a 10% ROE. KPCo also requested recovery of $50 million in deferred expenses related to the Rockport plant power purchase agreement (PPA) over a 5-year period beginning in December 2022. The KPSC decided to defer KPCo's request regarding the Rockport PPA recovery period and mechanism to a future proceeding.

The KPSC's January 2021 order also shortened the authorized period for the return of excess deferred income tax not subject to normalization to 3 years versus a previously (2018) authorized period of 18 years.

In October 2021, AEP agreed to sell its operations in Kentucky to Liberty Utilities Co., a subsidiary Algonquin Power and Utilities Corp (not rated) for an enterprise value of approximately $2.8 billion, including about $1.3 billion of estimated debt at closing. The transaction will close following approval by the FERC which we expect before the end of 2022.

For further information on AEP's subsidiaries, their service territories and recent regulatory activity please refer to each utility's credit opinion on Moodys.com.

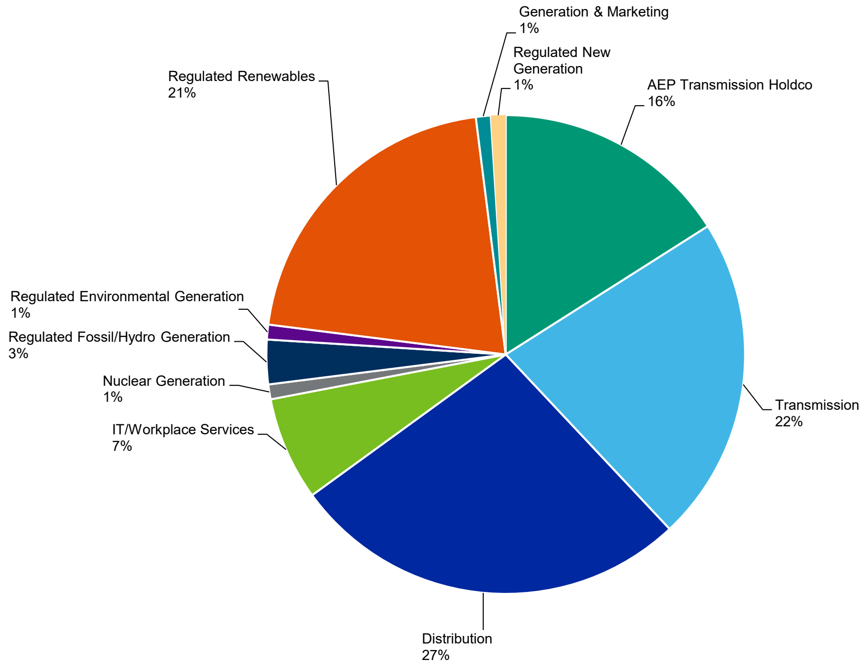
Substantial investments in regulated transmission networks, distribution, and environmental mandates

AEP has been investing heavily in its transmission and distribution networks to assure reliability throughout its service territories. For the twelve months ending 30 June 2022, AEP spent approximately $6 billion for capital expenditures, and its current five year capital forecast includes approximately $38 billion of investment planned for 2022 through 2026. This projected capital spending averages approximately $7.6 billion per year, significantly more than the $6 billion annual average over the last five years.

The $38 billion five-year capital investment plan is primarily focused on transmission and distribution investments which represent about 65% of total planned investments. The focus on transmission and distribution investing has resulted in a shift in physical assets, highlighting the changing composition of AEP's operations into lower risk businesses. As shown below, AEP's property, plant and equipment (PP&E) as of 30 June 2022 totaled approximately $80 billion, about 70% of which was transmission and distribution plant, with generation making up the remaining 30%. This compares with a PP&E profile in 2012 that totaled approximately $50 billion and consisted of 51% generation and 49% transmission and distribution plant.

Exhibit 5

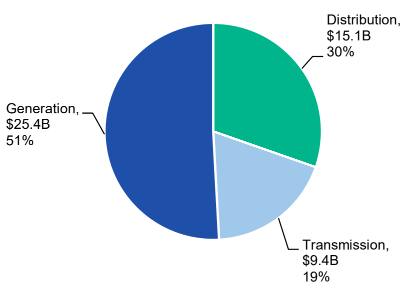
2022-2026 Capital forecast totals $38 billion



Source: Company presentations

Exhibit 6

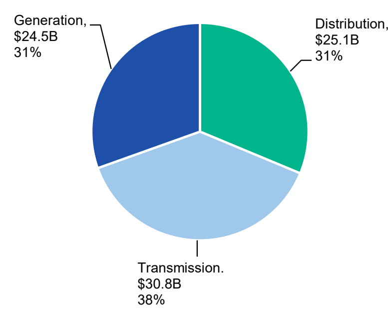
Q2 2012 Electric Property, Plant and Equipment: $49.9B



Source: Company filings

Exhibit 7

Q2 2022 Electric Property, Plant and Equipment: $80.3B



Source: Company filings

Transmission and distribution investments are expected to be largely recovered either through transmission formula based rates or rider recovery, a credit positive. Generation investment is primarily recovered in base rates and is more susceptible to lag in recovery. AEP estimates that more than 85% of its regulated capex spend during the 2022 - 2026 period will be recovered through forward rates or tracking mechanisms, reducing regulatory lag.

Additional debt financing for capex spend will maintain pressure on financial metrics

AEP's year-end financial metrics for 2020 and 2021 included interest coverage ratios of 4.6x and 4.2x and CFO pre-WC to debt ratios of 13.2% and 10.5%, respectively. The company's 2021 financial position was negatively impacted by costs associated with winter storm Uri in February 2021, and we estimate that, excluding these costs, the ratio of CFO pre-WC to debt would have been about 13.9%

Given AEP's overall elevated capital investment forecast, and the negative impact of federal tax reform on utility cash flow, including the accelerated return of deferred income taxes, the company's financial metrics will likely remain under pressure. Going forward, we expect company to stem the long-term decline in financial metrics and the ratio of CFO pre-WC to debt to stabilize be in a range of 13-15%, which will be important to the maintenance of its current rating.

ESG considerations

AEP's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 8
ESG Credit Impact Score

CIS-3
Moderately Negative

NEGATIVE IMPACT — POSITIVE IMPACT

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

AEP's ESG Credit Impact Score is moderately negative (**CIS-3**), where its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. AEP's **CIS-3** reflects moderately negative environmental and social risks, along with neutral to low governance risk.

Exhibit 9
ESG Issuer Profile Scores

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	S-3	G-2
Moderately Negative	Moderately Negative	Neutral-to-Low

Source: Moody's Investors Service

Environmental
AEP's moderately negative environmental risk (**E-3** issuer profile score) is driven primarily by its exposure to physical climate risks, mostly in the form of extreme weather patterns. These risks are offset by neutral to low exposure to carbon transition risk, as its significant transmission and distribution assets (~70% of PP&E) mitigate the fact that about 48% of its generation portfolio runs on coal. Risks in the areas of water management and natural capital are also neutral to low.

Social
Exposure to social risks is moderately negative (**S-3** issuer profile score), reflecting the risk that demographic and societal trends that increase public concern over environmental, social, or affordability issues could lead to adverse regulatory developments or political intervention. These risks are balanced by neutral to low exposure to health and safety, human capital, and customer relationship risks.

Governance
Governance is broadly in line with other utilities and does not pose a particular risk (**G-2** issuer profile). This is supported by neutral to low scores on financial strategy and risk management, management credibility and track record, organizational structure, compliance and reporting and board structure policies and procedures.

ESG Issuer Profile Scores and Credit Impact Scores for AEP are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for AEP on MDC and view the ESG Scores section.

Liquidity analysis

We expect AEP to maintain an adequate liquidity profile over the next 12-18 months. Although we anticipate that its significant investment program will result in negative free cash flow for the foreseeable future, the company has demonstrated capital markets access and its credit facilities currently provide reasonable near-term liquidity.

AEP's external liquidity is supported by two syndicated revolving credit facilities totaling $5.0 billion, with $1.0 billion expiring in March 2024 and the remaining $4.0 billion expiring in March 2027. Both facilities backstop its $3.5 billion commercial paper program which had $880 million outstanding as of 30 June 2022. AEP also has a receivables securitization agreement totaling $750 million where $125 million expires in September 2023 and $625 expires in September 2024. As of 30 June 2022, all $750 million of this securitization debt is outstanding.

AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under its credit agreement. Default provisions exclude a non-significant subsidiary (including its competitive generation subsidiary) cross default and insolvency/bankruptcy provisions. The facilities contain a covenant requiring that AEP's consolidated debt to capitalization (as defined) not exceed 67.5%. As of 30 June 2022, AEP states that its contractually defined debt to capitalization ratio was 57.8%.

As of 30 June 2022, AEP had consolidated long-term debt due within one year of approximately $2.5 billion. Near-term maturities within the AEP family include: $300 million of AEP senior notes maturing December 2022, $25 million of AEP Texas senior notes maturing in September 2022, $104 million of AEP Transco senior notes maturing in October 2022, $100 milion of APCo municipal bonds maturing in October 2022, and a $125 million PSO bank term loan maturing in October 2022.

Structural considerations

AEP's capital structure historically incorporated a very limited amount of holding company debt, a key credit positive compared to many holding company peers. However, in 2019, the company began increasing its use of parent level debt. As of 30 June 2022, AEP had long term parent level debt obligations of around $6.8 billion, or about 19% of its total long term debt. Inclusive of short-term debt, we estimate the ratio at approximately 23%. Going forward, we expect parent level debt to consolidated debt to remain under 25%.

Rating methodology and scorecard factors

Exhibit 10
Methodology Scorecard Factors
American Electric Power Company, Inc.

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2022		Moody's 12-18 Month Forward View As of Date Pubilshed[3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.7x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	12.7%	Ba	13% - 15%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	8.6%	Ba	9% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	54.1%	Baa	52% - 55%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		A3
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Scorecard-Indicated Outcome		Baa2		Baa1
b) Actual Rating Assigned		Baa2		Baa2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 06/30/2022 (FYE)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard risk grid for financial strength.
Source: Moody's Financial Metrics

Appendix

Exhibit 11

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
As Adjusted					
FFO	**4,649**	**4,648**	**5,016**	**3,934**	**4,935**
+/- Other	182	-220	-480	-65	457
CFO Pre-WC	**4,831**	**4,428**	**4,537**	**3,869**	**5,391**
+/- ΔWC	517	10	-509	236	661
CFO	**5,348**	**4,438**	**4,028**	**4,105**	**6,052**
- Div	1,256	1,355	1,433	1,529	1,586
- Capex	6,482	6,377	6,561	6,084	6,442
FCF	**-2,389**	**-3,294**	**-3,966**	**-3,508**	**-1,976**
(CFO Pre-W/C) / Debt	18.4%	14.4%	13.2%	10.5%	14.1%
(CFO Pre-W/C - Dividends) / Debt	13.6%	10.0%	9.0%	6.4%	9.9%
FFO / Debt	17.7%	15.1%	14.6%	10.7%	12.9%
RCF / Debt	12.9%	10.7%	10.4%	6.5%	8.8%
Revenue	16,196	15,561	14,919	16,792	17,917
Interest Expense	1,107	1,196	1,259	1,209	1,258
Net Income	1,679	1,949	2,149	2,505	2,570
Total Assets	69,492	75,524	80,691	87,669	90,861
Total Liabilities	50,593	55,872	59,733	64,778	66,328
Total Equity	18,899	19,652	20,958	22,890	24,533

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 12

Peer Comparison Table [1]

	American Electric Power Company, Inc. Baa2 (Stable)			Xcel Energy Inc. Baa1 (Stable)			Duke Energy Corporation Baa2 (Stable)			Eversource Energy Baa1 (Negative)			Berkshire Hathaway Energy Company A3 (Stable)		
(In US millions)	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Mar-22	FYE Dec-21	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22
Revenue	14,919	16,792	17,917	11,526	13,431	13,997	23,868	25,097	26,079	8,904	9,863	10,959	20,952	25,150	25,647
CFO Pre-W/C	4,537	3,869	5,391	3,408	2,836	4,058	9,407	9,941	10,255	2,026	2,516	2,484	7,323	8,541	8,634
Total Debt	34,307	36,746	38,267	21,183	23,602	24,209	63,702	69,474	71,677	19,800	20,638	21,842	55,406	53,822	54,716
CFO Pre-W/C + Interest / Interest	4.6x	4.2x	5.3x	5.0x	4.4x	5.7x	5.1x	5.2x	5.2x	4.5x	5.1x	4.9x	4.7x	5.0x	5.0x
CFO Pre-W/C / Debt	13.2%	10.5%	14.1%	16.1%	12.0%	16.8%	14.8%	14.3%	14.3%	10.2%	12.2%	11.4%	13.2%	15.9%	15.8%
CFO Pre-W/C – Dividends / Debt	9.0%	6.4%	9.9%	12.0%	8.1%	12.7%	10.4%	9.9%	10.0%	6.5%	8.3%	7.5%	13.0%	14.8%	14.8%
Debt / Capitalization	53.8%	54.0%	53.5%	52.4%	53.5%	53.9%	52.5%	53.7%	54.4%	52.1%	51.7%	52.3%	49.3%	46.2%	46.0%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 13

Category	Moody's Rating
AMERICAN ELECTRIC POWER COMPANY, INC.	
Outlook	Stable
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2
APPALACHIAN POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Other Short Term	P-2
AEP TEXAS INC.	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
AEP TRANSMISSION COMPANY, LLC	
Outlook	Stable
Issuer Rating	A2
Senior Unsecured	A2
SOUTHWESTERN ELECTRIC POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
INDIANA MICHIGAN POWER COMPANY	
Outlook	Positive
Issuer Rating	A3
Senior Unsecured	A3
OHIO POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
PUBLIC SERVICE COMPANY OF OKLAHOMA	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
AEP TEXAS CENTRAL COMPANY	
Outlook	No Outlook
Senior Unsecured	Baa2
COLUMBUS SOUTHERN POWER COMPANY	
Outlook	No Outlook
Senior Unsecured	Baa1
RGS (AEGCO) FUNDING CORPORATION	
Outlook	Positive
Bkd Senior Secured	A3
RGS (I&M) FUNDING CORPORATION	
Outlook	Positive
Bkd Senior Secured	A3
KENTUCKY POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa3
Senior Unsecured	Baa3
AEP GENERATING COMPANY	
Outlook	
Bkd LT IRB/PC	Baa2

Source: Moody's Investors Service

REPORT NUMBER 1340399

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Research Update:

Kentucky Power Co. CreditWatch Implications Revised To Negative From Developing On AEP Sale Agreement

October 28, 2021

Rating Action Overview

- American Electric Power Co. Inc. (AEP) announced that it has reached an agreement to sell Kentucky Power Co. (KPCo) and a Kentucky transmission entity to Algonquin Power & Utilities Corp. (APUC) for about $2.85 billion, including assumed debt of about $1.2 billion. The transaction is expected to close by the end of the second quarter of 2022.
- We revised the CreditWatch implications on KPCo to negative from developing on our 'BBB+' issuer credit rating and issue-level ratings on its senior unsecured debt. We previously placed the ratings on CreditWatch with developing implications on April 28, 2021.
- The revised CreditWatch placement reflects the announced sale of KPCo to lower-rated APUC, which is below our issuer credit rating on KPCo.

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Rating Action Rationale

We revised the CreditWatch implications on KPCo to negative from developing. The CreditWatch with negative implications reflects our expectation that we will likely downgrade KPCo by one notch as APUC, the acquiring entity, is currently rated 'BBB', and we expect to align our ratings on KPCo with those on APUC.

Our assessment of KPCo's stand-alone credit profile (SACP) remains 'bbb'. We continue to assess the company's business risk as strong and its financial risk as significant. Our business risk assessment reflects the regulatory support KPCo receives in Kentucky. The company was under a three-year base rate stay-out through 2020. The recent increase in KPCo's revenue supports its credit quality because it will enable it to recover a higher level of its capital and operating expenses. The company has a small customer base of about 170,000 and limited geographic diversity given that it operates almost entirely in Kentucky. That said, KPCo's service territory demonstrates modest growth. The company derives about half of its energy sales from industrial customers, which leads to less stability in its operating cash flow than if its customer base was entirely residential. KPCo continues to be exposed to energy transition risks because of its coal-fired generation, which accounts for most of its generation capacity.

We assess the company's financial risk profile as significant, which reflects its financial measures, including our expectation for funds from operations (FFO) to debt of 16%-17% through 2023. Our assessment of KPCo's financial risk profile incorporates its recently approved rate case, which will strengthen its financial risk. We use our medial volatility table benchmarks to assess KPCo's financial risk, which are more relaxed benchmarks than those we use for typical corporate issuers. This reflects the company's steady cash flows, low-risk rate-regulated utility operations, and effective management of regulatory risk.

Our assessment of KPCo's group status as moderately strategic lifts our issuer credit rating on the company by one notch above its SACP to account for its limited group support.

CreditWatch

The CreditWatch placement reflects AEP's announced sale of KPCo to lower-rated APUC. We expect to remove the CreditWatch and lower the ratings on KPCo to align with the lower-rated parent as the acquiring company nears or completes the transaction.

Ratings Score Snapshot

Issuer Credit Rating: BBB+/Watch Neg/--

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bbb

- Group credit profile: a-
- Entity status within group: Moderately strategic (+1 notch from SACP)

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Ratings Unchanged; CreditWatch Action

	To	From
Kentucky Power Co.		
Issuer Credit Rating	BBB+/Watch Neg/--	BBB+/Watch Dev/--
Senior Unsecured	BBB+/Watch Neg	BBB+/Watch Dev

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE 103.57 | P/E RATIO 19.9 (Trailing: 19.8 Median: 17.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 4/1/22
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 6/10/22
BETA .75 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$83-$115 $99 (-5%)

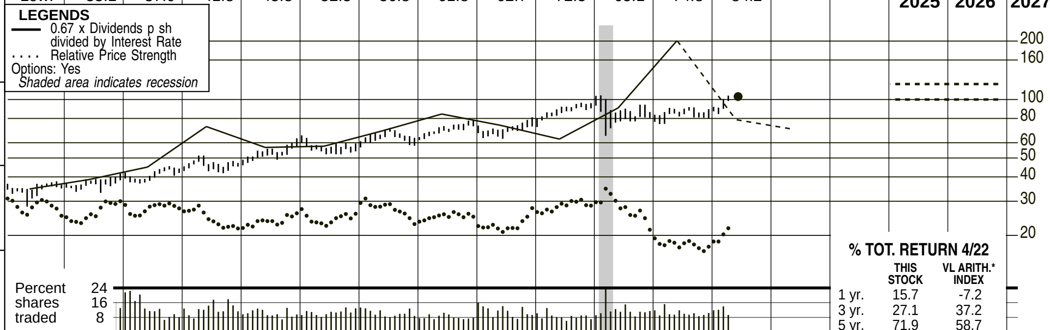
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+15%)	7%
Low	100	(-5%)	3%

Institutional Decisions

	3Q2021	4Q2021	1Q2022
to Buy	561	636	673
to Sell	433	473	475
Hld's(000)	373255	373909	382433

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	104.8
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	84.2



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.7	-7.2
3 yr.	27.1	37.2
5 yr.	71.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	*35.20*	*35.95*	Revenues per sh	*38.50*
6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	*11.50*	*11.95*	"Cash Flow" per sh	*14.00*
2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	*5.20*	*5.35*	Earnings per sh A	*6.50*
1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	*3.17*	*3.35*	Div'd Decl'd per sh B ■ †	*4.00*
8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	*15.35*	*14.15*	Cap'l Spending per sh	*14.00*
23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	*47.30*	*50.30*	Book Value per sh C	*59.00*
396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	*514.00*	*523.00*	Common Shs Outst'g D	*545.00*
12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93	*Value Line*		Relative P/E Ratio	*.95*
4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $37244 mill. **Due in 5 Yrs** $12886 mill.
LT Debt $30856 mill. **LT Interest** $1067 mill.
Incl. $603.5 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill. **Oblig** $5187.0 mill.
Pfd Stock None

Common Stock 513,544,176 shs.
as of 4/28/22
MARKET CAP: $53 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	*18100*	*18800*	Revenues ($mill)	*21000*
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	*2670*	*2790*	Net Profit ($mill)	*3565*
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	*57775*	*62950*	Total Capital ($mill)	*75900*
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	*70650*	*74600*	Net Plant ($mill)	*87300*
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	*4.5%*	*4.0%*	Retained to Com Eq	*4.5%*
63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	*63%*	*64%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	3.5%
"Cash Flow"	4.5%	5.0%	5.5%
Earnings	4.5%	4.0%	6.5%
Dividends	5.0%	6.0%	6.0%
Book Value	4.0%	3.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	*4107*	*4950*	*4450*	*18100*
2023	*4800*	*4300*	*5150*	*4550*	*18800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	*1.15*	*1.64*	*1.00*	*5.20*
2023	*1.30*	*1.25*	*1.75*	*1.05*	*5.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78			

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power should soon complete an asset sale, and the company is interested in divesting other assets. AEP expects to raise $1.45 billion from the sale of its Kentucky Power subsidiary, which has not been earning an adequate return on equity. This is expected to be completed by the end of this month. The company also wants to sell its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. We will *include* any gains on these sales in our earnings presentation. AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than nonutility assets, and electric transmission.

We expect respectable earnings growth in 2022 and 2023. We raised our estimate for this year by $0.20 a share, to $5.20, thanks to a $0.20 mark-to-market credit that AEP booked in the first quarter. Our revised estimate is within management's guidance (on a GAAP basis) of $5.06-$5.26 a share. Otherwise, the company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Some industrial customers in its service area have expansions that are expected to come on later this year, despite the state of the national economy.

Some regulatory matters are pending or were concluded. The SWEPCO subsidiary was granted $28 million in Arkansas, based on a 9.5% return on equity and a 45% common-equity ratio. New tariffs will take effect on July 1st. In Louisiana, the utility requested $73 million, based on a 10.35% ROE and a 50.8% common-equity ratio. (This is net of increases in depreciation and amortization.) In Virginia, Appalachian Power is appealing an unfavorable rate order to the state Supreme Court. A decision is expected later in 2022. Note that the company has already received rate increases in Texas and Indiana this year.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and the 3- to 5-year period. The recent quotation is within our 2025-2027 Target Price Range. The stock price has risen 16% year to date.

Paul E. Debbas, CFA *June 10, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due late July. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '21: $17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
29 June 2022

Update

Send Your Feedback

RATINGS

Kentucky Power Company

Domicile	Ashland, Kentucky, United States
Long Term Rating	Baa3
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Kentucky Power Company

Update to credit analysis

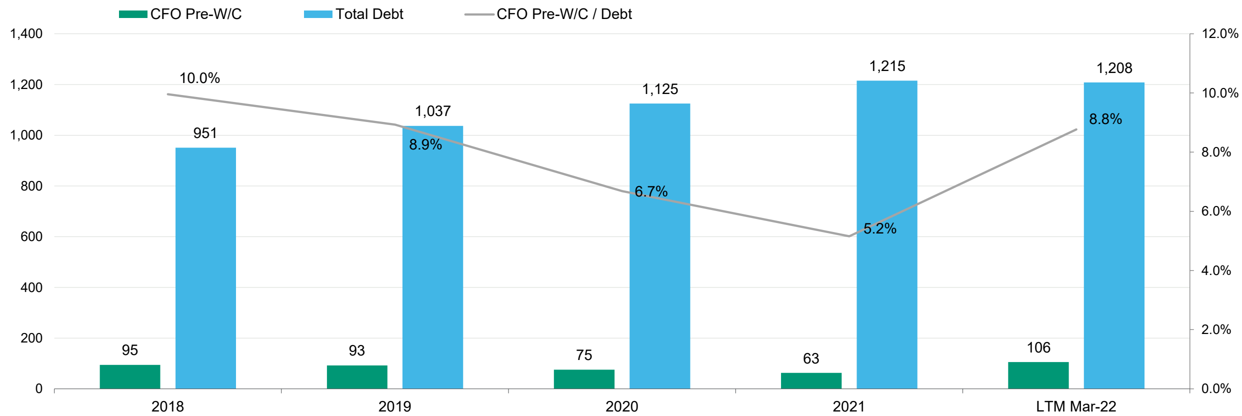
Summary

Our view of Kentucky Power Company's (KPCo) credit reflects its risk profile as a vertically integrated electric utility operating in eastern Kentucky. Our opinion reflects the lower cash flow and cash flow-based credit metrics the company has demonstrated in recent years as a result of under earning and required refunds in an economically challenged service territory. Recent credit metrics are also being impacted by storm activity. KPCo's 2021 ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt was particularly low, at 5.2%, due to costs associated with unusually severe winter weather in February 2021. Excluding the impact of this unusual weather, the company's 2021 CFO pre-WC to debt ratio would be about 10%. We expect the utility's credit metrics to improve after 2022, including a ratio of CFO pre-WC to debt ratio above 10%, following the expiration of a relatively high cost lease agreement. The stable outlook on KPCo reflects our view that, barring major changes to the utility's financial condition or debt levels as a result of its pending acquisition discussed below, we do not expect the sale to adversely affect the current rating.

Recent Developments

In October 2021, KPCo's parent, American Electric Power Company (AEP, Baa2 stable), agreed to sell KPCo and AEP Kentucky Transco to Liberty Utilities Co., a subsidiary Algonquin Power and Utilities Corp (not rated) for an enterprise value of approximately $2.8 billion, including about $1.3 billion of estimated debt at closing. In May 2022, the Kentucky Public Service Commission (KPSC) approved the sale. The sale was expected to close in the second quarter of 2022 following approvals required from the West Virginia Public Service Commission (WVPSC) and the Federal Energy Regulatory Commission (FERC). However, approval from the WVPSC of operating and ownership agreements related to the Mitchell power plant is still pending and FERC has indicated that it will require up to 180 days to render a decision following receipt of the WVPSC approval. AEP expects the sale to close in summer 2022 but closing could occur as late as December 2022.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($ in millions)



Source: Moody's Financial Metrics

Credit strengths

» Reasonable regulatory relationship in Kentucky

» Position as part of the AEP family to be replaced by smaller but still diverse Liberty utility family

Credit challenges

» Increasing capital expenditures and cash deferrals will continue to pressure already low credit metrics

» Relatively weak service territory in eastern Kentucky

» Elevated carbon transition risk

Rating outlook

KPCo's stable rating outlook recognizes that its low cash flow-based credit metrics will continue to be impacted by a relatively weak service territory, recent severe weather, and a significant capital expenditure program. Cash flow is also being pressured by deferrals agreed to in the utility's 2018 decided rate case and an accelerated return of excess deferred income taxes. We expect KPCo's annual ratio of CFO pre-WC to debt to remain below 10% through 2022. Beyond 2022, the expiration of a relatively high cost lease agreement should help this metric to move to the low teens. The stable outlook also reflects our view that, barring major changes to the utility's financial condition or debt levels as a result of the acquisition by Liberty, we do not expect the sale to adversely affect the current rating.

Factors that could lead to an upgrade

» An improvement in economic conditions, or a reduction in operating or capital expenses, leading to improved financial performance

» A sustained ratio of CFO pre-WC to debt above 13% with a ratio of CFO pre-WC less dividends above 11%

» A material reduction in leverage at the utility

Factors that could lead to a downgrade

» A deterioration in KPCo's relationship with its regulator

» An increase in capital or operating expenses that KPCo is unable to recover on a timely basis

» A ratio of CFO pre-WC to debt remaining below 10% beyond 2022

Key indicators

Exhibit 2

Kentucky Power Company Indicators [1]

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Mar-22
CFO Pre-W/C + Interest / Interest	3.4x	3.2x	2.9x	2.7x	3.9x
CFO Pre-W/C / Debt	10.0%	8.9%	6.7%	5.2%	8.8%
CFO Pre-W/C – Dividends / Debt	10.0%	8.4%	6.7%	5.2%	8.8%
Debt / Capitalization	45.6%	46.4%	47.0%	48.1%	47.5%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Kentucky Power Company (KPCo), a vertically integrated electric utility company headquartered in Ashland, Kentucky, is a wholly owned subsidiary of AEP, with about $2.0 billion in rate base (4% of AEP's total) and 2021 revenue of about $650 million (about 4% of AEP's total revenue). The utility is primarily regulated by the Kentucky Public Service Commission (KPSC). AEP has agreed to sell KPCo to Liberty Utilities Company, a holding company of regulated utilities, with AEP expecting the closing to occur in summer 2022.

Detailed credit considerations

Reasonable regulatory relationship

Moody's views the regulatory environment in Kentucky as moderately supportive of long-term credit quality. KPCo benefits from a suite of cost recovery mechanisms that help reduce regulatory lag, including a fuel adjustment clause, rider recovery for certain PJM transmission costs, and environmental recovery riders which enable utilities in the state to earn a return on construction work in progress. In addition, utilities in Kentucky can start to collect interim rates approximately six months after filing a rate case if the KPSC has not acted on it. Despite these positive factors, the KPSC's recent decisions have been impacted by the weak economic conditions in KPCo's service territory and have been less supportive of utility credit quality.

In January 2021, the KPSC authorized a $52.4 (later modified to $52.7) million base rate increase premised on a 9.3% return on equity (ROE). The case was initiated in June of 2020 when KPCo filed a request for a $65 million increase in base rates premised on a 10% ROE. The KPSC's order shortened the authorized period for the return of excess deferred income tax not subject to normalization to 3 years versus a previously (2018) authorized period of 18 years.

AEP Generating Company (AEGCo, not rated) sells 30% of the power available to AEGCo from units 1 (of which it owns a 50% interest) and 2 (of which it leases a 50% interest) of the Rockport Power Plant to KPCo. This sale is pursuant to an assignment between KPCo and sister company Indiana Michigan Power Company (I&M, A3 positive), which has a unit power agreement (UPA) with AEGCo for all the power available to AEGCo from the two Rockport plant units. Consequently, KPCo pays to AEGCo the same amounts which I&M would have paid to AEGCo under the terms of the UPA. In its last rate case, KPCo requested recovery of $50 million in deferred expenses related to the Rockport plant power purchase agreement (PPA) over a 5-year period beginning in December 2022. KPCo had agreed to defer this $50 million over five years, through 2022 as part of its 2018 decided rate case. The KPSC decided to defer KPCo's request regarding the Rockport PPA recovery period and mechanism to a future proceeding.

The proceeding to determine recovery of the deferred $50 million of PPA costs will be initiated after KPCo makes a written filing identifying the capacity replacement for Rockport unit 2. We expect the company will make that filing after the close of its pending sale. In the interim, the KPSC has allowed KPCo to retain savings from the December 2022 Rockport unit 2 lease expiration through at least 2023 when the utility is required to file its next rate case. KPCo's parent, AEP, has reached an agreement with the Rockport unit 2 lessor to acquire the unit at the end of its lease term in 2022, thus the capacity will remain within the AEP organization.

Cash flow credit metrics are under pressure

Prior to 2018, KPCo's key cash flow based financial credit metrics were strong for its credit quality, including CFO pre-WC to debt in the mid-to-high teens. Since then, cash flow metrics have declined fairly dramatically as the utility's debt load increased in conjunction with its capital program, while sales volumes have been negatively impacted by challenging economic conditions.

For the past three years, KPCo's ratio of CFO pre-WC to debt has been below the 10% financial metric threshold we have established for a possible downgrade. As noted above, weak economic conditions, the coronavirus pandemic, severe weather, and PPA related deferrals have all contributed to this result. Excluding the impact of unusual winter weather, the company's 2021 CFO pre-WC to debt ratio would be about 10%. The company intends to request recovery of approximately $60 million of storm costs in its next base rate case. We expect the utility's credit metrics to remain low in 2022 but the expiration of the relatively high cost Rockport lease agreement should help the ratio of CFO pre-WC to debt metric to move to the low teens beyond 2022.

As a subsidiary of AEP, the company has had flexibility with regards to dividend policy including the credit supportive ability to retain cash in response to lower cash flow. In 2019, a minimal $5 million dividend was paid; however in 2018, 2020 and 2021, no dividends were paid to AEP. As a result, KPCo's ratios of CFO pre-WC less dividends to debt have essentially been equal to its relatively low ratios of CFO pre-WC to debt.

Upon completion of the sale of KPCo, Liberty Utilities' plan for the utility, including capital spending and financial policy, could change, but barring any significant changes, we do not expect the sale to adversely affect KPCo's current rating.

Sale of KPCo contingent on new Mitchell plant operating and ownership agreements

KPCo's owned generation includes 50% of the 1,560 MW Mitchell coal power plant, with the other 50% owned by AEP subsidiary Wheeling Power Company (WPCo). In July 2021, the KPSC rejected KPCo's request to implement an Effluent Limitation Guidelines (ELG) compliance plan which would allow the Mitchell plant to operate beyond 2028. However, in August 2021, the West Virginia Public Service Commission (WVPSC) approved the plan.

In response to the conflicting decisions of the two regulatory commissions, KPCo and WPCo filed for approval of new operating and ownership agreements for the Mitchell plant, which is currently operated by KPCo. The filings request that operation of the plant be transferred to WPCo and the employees who operate the Mitchell plant be transferred from KPCo to WPCo. Furthermore, WPCo would be obligated to purchase KPCo's 50% interest in the Mitchell plant at the end of 2028 unless both companies decide to retire the plant earlier or WPCo elects before 31 December 2027 to retire the plant by 31 December 2028. AEP's sale of the Kentucky operations is contingent on approval by the KPSC, WVPSC and FERC of the new Mitchell plant operating and ownership agreements. In May 2022, the KPSC approved the sale of AEP's Kentucky operations as well as the new Mitchell operating and ownership agreements with conditions including on the buyout provisions under the ownership agreement. Approval from the WVPSC is pending and AEP intends to file for FERC approval once it receives approval from the WVPSC. FERC has indicated that it will require up to 180 days to render a decision and while AEP expects the sale to be completed in summer 2022, closing could occur as late as December 2022.

Service territory economy remains depressed

According to Moody's Economy, Kentucky's economic recovery has cooled off and the state remains an underperformer compared to most regional peers. Manufacturing gains, specifically in the automotive sector will continue to be muted until supply-chain bottlenecks ease. These complications will leave consumer services driving the majority of job gains in the short-term. However, longer term, capital injections will support higher levels of factory employment, including large investments for electric vehicle factories from Ford, Kentucky's third largest employer.

KPCo has been actively working with state and federal officials to foster economic development in eastern Kentucky that will bring job opportunities, increase customer retention, and support load growth. However, these efforts have yet to begin to meaningfully contribute to utility load growth or cash flow. Approximately 24% of KPCo's 2021 retail energy revenues were from industrial customers. Total weather normalized retail load remained flat in 2021 following an 8.4% decline in 2020, and declines of 2.1% in 2019, 0.7% in 2018, and 1.7% in 2017.

ESG considerations

Environmental considerations incorporated into our credit analysis for KPCo are primarily related to carbon regulations. As an integrated electric utility, KPCo's generation ownership places it at a higher risk profile than transmission and distribution companies. In addition, its significant coal generation ownership results in a higher ESG risk profile than other vertically integrated electric utilities.

KPCo's total owned generation capacity of 1,060 MW includes a 50% ownership in the coal-fired Mitchell plant (780 MW) and the gas-fired Big Sandy Unit 1 (280 MW). KPCo also purchases approximately 393 MW from its affiliate AEP Generating Company's share of the Rockport coal plant under a long-term unit power agreement, bringing its overall capacity mix to 20% natural gas and 80% coal. Both units of the Rockport plant are currently expected to be retired in 2028.

Social risks are primarily related to demographic and societal trends, including the risk that public concern about environmental, social or affordability issues could result in adverse regulatory or political outcomes.

Governance is driven by that of KPCo's parent and will be driven by that of Liberty Utilities and ultimate parent Algonquin Power and Utilities Corp. once the sale of KPCo is completed. Conservative financial policies and risk management that ensure a strong financial position are key to managing KPCo's environmental and social risks.

Liquidity analysis

KPCo's liquidity is adequate. For the twelve months ending 31 March 2022, KPCo generated approximately $38 million of cash from operations, invested $170 million in capital expenditures and paid no dividends to parent AEP, resulting in a negative free cash flow (FCF) of approximately $131 million. We expect KPCo to remain free cash flow negative over the next 12 to 18 months.

Although KPCo does not benefit from a dedicated external credit facility, the company does have access to its parent company AEP's liquidity through participation in its utility money pool. As of 31 March 2022, KPCo's borrowing limit under the money pool was $180 million and the utility had borrowed approximately $94 million. KPCo has historically utilized AEP's $750 million receivable securitization facility, made up of a $125 million and $625 million facility expiring September 2023 and 2024 respectively. Due to the pending sale to Liberty Utilities, KPCo terminated selling receivables to AEP Credit in January 2022 and recorded an allowance for uncollectible accounts in the first quarter of 2022 for receivables no longer sold to AEP Credit. KPCo's nearest maturities include a $125 million term loan due in September 2022 and a $75 million term loan due in October 2022. We expect these to be refinanced.

AEP's consolidated liquidity is adequate. AEP currently has two syndicated credit facilities, a $4.0 billion facility expiring in March 2027, and a $1.0 billion facility expiring in March 2024. As of 31 March 2022, AEP had approximately $1.88 billion of outstanding commercial paper utilizing capacity under the $4 billion facility. AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under its revolving credit facilities. The facility contains a covenant requiring that AEP's consolidated debt to capitalization (as defined) not exceed 67.5%. AEP states that the contractually defined ratio was 57.8% at 31 March 2022.

Appendix

Exhibit 3

Peer Comparison [1]

	Kentucky Power Company Baa3 (Stable)			Duke Energy Kentucky, Inc. Baa1 (Stable)			Louisville Gas & Electric Company A3 (Stable)			Kentucky Utilities Co. A3 (Stable)		
(In US millions)	FYE Dec-20	FYE Dec-21	LTM Mar-22	FYE Dec-19	FYE Dec-20	LTM Dec-21	FYE Dec-19	FYE Dec-20	LTM Dec-21	FYE Dec-21	FYE Dec-21	LTM Mar-22
Revenue	550	646	667	452	520	520	1,456	1,569	1,569	1,690	1,826	1,882
CFO Pre-W/C	75	63	106	125	145	145	535	543	543	646	664	683
Total Debt	1,125	1,215	1,208	885	921	921	2,290	2,417	2,417	2,851	2,938	2,934
CFO Pre-W/C + Interest / Interest	2.9x	2.7x	3.9x	5.5x	6.3x	6.3x	7.1x	7.7x	7.7x	6.7x	7.0x	7.2x
CFO Pre-W/C / Debt	6.7%	5.2%	8.8%	14.1%	15.7%	15.7%	23.4%	22.5%	22.5%	22.7%	22.6%	23.3%
CFO Pre-W/C – Dividends / Debt	6.7%	5.2%	8.8%	14.1%	15.7%	15.7%	16.3%	14.5%	14.5%	15.6%	14.1%	13.6%
Debt / Capitalization	47.0%	48.1%	47.5%	48.0%	45.8%	45.8%	38.5%	38.7%	38.7%	38.2%	38.0%	37.9%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 4

Cash flow and credit measures [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Mar-22
As Adjusted					
FFO	**119**	**130**	**127**	**131**	**134**
+/- Other	-25	-38	-52	-68	-28
CFO Pre-WC	**95**	**93**	**75**	**63**	**106**
+/- ΔWC	27	-10	-9	10	-15
CFO	**122**	**82**	**66**	**73**	**91**
- Div	0	5	0	0	0
- Capex	138	163	157	169	174
FCF	**-16**	**-86**	**-91**	**-96**	**-83**
(CFO Pre-W/C) / Debt	10.0%	8.9%	6.7%	5.2%	8.8%
(CFO Pre-W/C - Dividends) / Debt	10.0%	8.4%	6.7%	5.2%	8.8%
FFO / Debt	12.6%	12.6%	11.3%	10.8%	11.1%
RCF / Debt	12.6%	12.1%	11.3%	10.8%	11.1%
Revenue	642	619	550	646	667
Interest Expense	40	42	39	36	37
Net Income	54	50	40	50	62
Total Assets	2,465	2,612	2,734	2,894	2,894
Total Liabilities	1,735	1,834	1,911	2,020	1,994
Total Equity	730	778	823	874	900

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Rating methodology and scorecard factors

Exhibit 5
Kentucky Power Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2022		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Baa	Baa	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.0x	Ba	4x - 4.5x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	6.8%	Ba	8% - 13%	Ba
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	6.7%	Ba	8% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	46.9%	Baa	45% - 50%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa3		Baa3
HoldCo Structural Subordination Notching				
a) Scorecard-Indicated Outcome		Baa3		Baa3
b) Actual Rating Assigned		Baa3		Baa3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2022 (LTM)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard Risk Grid for Financial Strength
Source: Moody's Financial Metrics

Ratings

Exhibit 6

Category	Moody's Rating
KENTUCKY POWER COMPANY	
Outlook	Stable
Issuer Rating	Baa3
Senior Unsecured	Baa3
PARENT: AMERICAN ELECTRIC POWER COMPANY, INC.	
Outlook	Stable
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

Source: Moody's Investors Service

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Research Update:

Kentucky Power Co. Downgraded To 'BBB+', On CreditWatch Developing On Announced Sale By Parent American Electric Power

April 28, 2021

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Rating Action Overview

- Following its strategic review, American Electric Power Co. Inc. (AEP) announced that it has launched a process to sell utility affiliate Kentucky Power Co. (KPCo).
- We revised our assessment of KPCo's group status to moderately strategic from core. However, our 'bbb' stand-alone credit profile (SACP) remains unchanged based on our strong business risk assessment and significant financial risk assessment.
- We lowered our issuer credit rating (ICR) and senior unsecured issue-level rating on KPCo to 'BBB+' from 'A-' and placed them on CreditWatch with developing implications.
- The CreditWatch placement reflect the company's expected sale and the material uncertainty around its ultimate buyer and the buyer's credit profile.

Rating Action Rationale

We revised our assessment of KPCo's group status to moderately strategic from core. Our reassessment of KPCo's group status incorporates its parent's ongoing strategic review. Although KPCo may be sold, its continued to access the AEP money pool, which indicates it is receiving some level of group support.

Our SACP on KPCo remains 'bbb'. We continue to assess the company's business risk as strong and its financial risk as significant. Our strong business risk assessment reflects the regulatory support KPCo receives in Kentucky. The company was under a three-year base rate stay-out through 2020. The recent increase in KPCo's revenue supports its credit quality because it will enable it to recover a higher level of its capital and operating expenses. The company has a small customer base of about 170,000 and limited geographic diversity given that it operates almost entirely in Kentucky. That said, KPCo's service territory demonstrates modest growth. The company derives about half of its energy sales from industrial customers, which leads to less stability in its operating cash flow than if its customer base was entirely residential. KPCo continues to be exposed to coal-fired generation, which accounts for the majority of its generation capacity.

Our revised assessment of KPCo's group status as moderately strategic lifts our issuer credit rating on the company by one notch above its SACP to account for its limited group support.

We assess the company's financial risk profile as significant, which reflects its financial measures, including our expectation for funds from operations (FFO) to debt of 14%-17% through 2022. Our assessment of KPCo's financial risk profile incorporates its recently approved rate case, which will strengthen its financial risk. We use our medial volatility table benchmarks to assess KPCo's financial risk, which are more relaxed benchmarks than those we use for typical corporate issuers. This reflects the company's steady cash flows, low-risk rate-regulated utility operations, and effective management of regulatory risk.

CreditWatch

The CreditWatch placement reflects AEP's announcement that it will sell KPCo, though the company offered no indication of the ultimate buyer or its credit quality. Once we receive more clarity about the timing of the sale and the ultimate buyer, we will update our CreditWatch placement.

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded; Placed on CreditWatch

	To	From
Kentucky Power Co.		
Issuer Credit Rating	BBB+/Watch Dev/--	A-/Stable/--
Issue-Level Ratings Lowered; Placed on CreditWatch		
Kentucky Power Co.		
Senior Unsecured	BBB+/Watch Dev	A-

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Kentucky Power Co.

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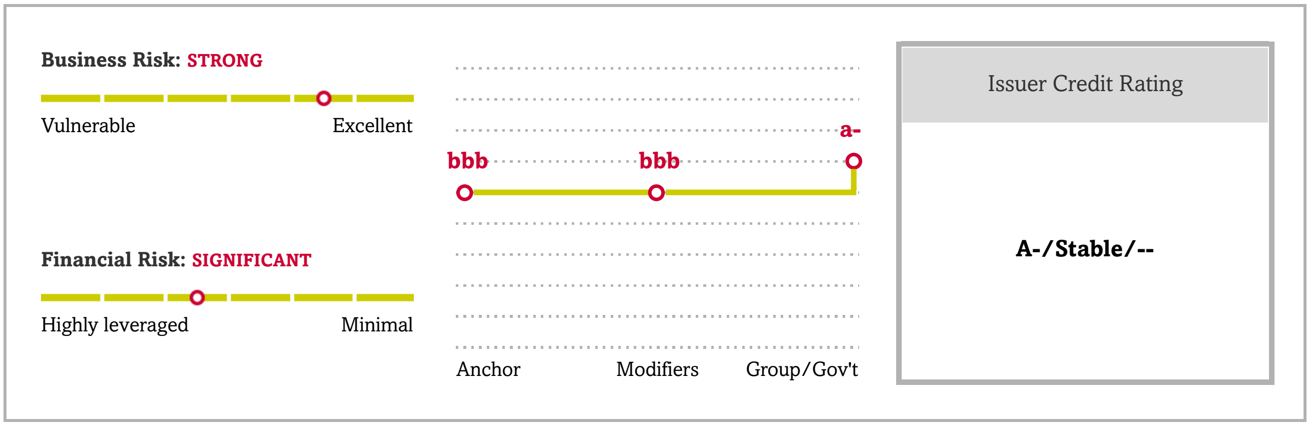
Kentucky Power Co.



Credit Highlights

Overview

Key strengths	Key risks
Lower-risk vertically integrated regulated electric utility.	Limited geographic diversity and small customer base.
Credit-supportive and constructive regulatory framework in Kentucky.	Coal-fired generation increases environmental compliance exposure.
Balanced capital structure supports overall credit quality.	Customer concentration, with industrial customers contributing about one-half of the energy sales.

Kentucky Power Co. (KPCo) operates under a credit-supportive framework. Kentucky's commission offers a constructive regulatory framework that provides for the timely recovery of approved capital expenditures. The commission has also approved pass-through fuel cost mechanisms reducing cash flow volatility.

Debt leverage will increase in the forecast period. Debt to EBITDA is expected to remain higher in the mid- to high-5x area over the next few years from greater use of debt to fund capital spending.

There is a rate freeze until December 2020. KPCo is under a three-year base rate stay-out and the company cannot request a rate increase before Jan. 1, 2021.

Outlook: Stable

The stable rating outlook on KPCo reflects that of its parent American Electric Power Co. Inc. (AEP). The stable outlook on AEP and its subsidiaries reflects its improving business risk profile consisting almost entirely of solid regulated utility operations. We expect AEP to generate funds from operations (FFO) to debt of 15%-16% through 2021 after factoring in the impact of U.S. tax reform.

Downside scenario

We could lower the ratings on AEP and its subsidiaries if its financial performance weakens such that FFO to debt is consistently below 14%, or if its business risk increases as a result of ineffective regulatory risk management or the pursuit of risky unregulated investments.

Upside scenario

While not likely, we could raise the ratings on AEP and its subsidiaries if its financial performance improves, with FFO to debt consistently above 20% while business risk is unchanged.

Our Base-Case Scenario

Assumptions

- EBITDA margin averaging about 16% through 2022.
- Effective management of regulatory risk and continued recovery of prudent costs.
- Elevated capital spending of $170 million-$200 million per year driven by infrastructure investments.
- All debt maturities refinanced.

Key Metrics

	2020e	2021e	2022e
Adjusted FFO to debt (%)	14-16	15-17	15-17
Adjusted debt to EBITDA (x)	5-5.5	4.5-5	4.5-5
Adjusted FFO cash interest coverage (x)	4-4.5	4.5-4.9	4.5-4.9

e--Expected. FFO--Funds from operations.

Company Description

KPCo is a vertically integrated electric utility serving about 170,000 customers in eastern Kentucky. It also sells electricity at wholesale to municipalities.

Business Risk: Strong

Our assessment of KPCo's business risk profile reflects the company's lower-risk vertically integrated electric utility business that operates under a generally constructive regulatory framework. KPCo has a small customer base of around 170,000 and limited geographical diversity since it operates almost entirely in Kentucky. The service territory demonstrates modest growth. Industrial customers contribute about one-half of the energy sales, leading to less stable operating cash flow.

Under Kentucky Public Service Commission regulation, the company benefits from a fuel-cost adjustment mechanism that provides for incremental cost recovery when fuel costs rise. Moreover, the company's low-cost, coal-fired generation and efficient operations contribute to overall competitive rates for customers. KPCo has been able to receive timely recovery of approved capital expenditures.

KPCo's higher exposure to coal generation, at about 75%, could lead to greater environmental compliance costs.

Table 1

Peer Comparison

Industry sector: electric

	Kentucky Power Co.	Kentucky Utilities Co.	Louisville Gas & Electric Co.
Ratings as of April 2, 2020	A-/Stable/--	A-/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2018--		
(Mil. $)			
Revenue	642.1	1,760.0	1,496.0
EBITDA	203.0	774.8	618.9
FFO	165.8	650.2	533.7
Interest expense	41.9	118.6	93.8
Cash interest paid	40.4	99.5	78.2
Cash flow from operations	118.2	589.2	454.7
Capital expenditure	134.8	562.5	555.2
FOCF	(16.6)	26.7	(100.5)
DCF	(16.6)	(219.3)	(256.5)
Cash and short-term investments	1.2	14.0	10.0
Debt	938.0	2,817.7	2,297.0
Equity	732.9	3,442.0	2,687.0
Adjusted ratios			
EBITDA margin (%)	31.6	44.0	41.4
Return on capital (%)	6.5	7.8	8.0
EBITDA interest coverage (x)	4.8	6.5	6.6
FFO cash interest coverage (x)	5.1	7.5	7.8
Debt/EBITDA (x)	4.6	3.6	3.7
FFO/debt (%)	17.7	23.1	23.2
Cash flow from operations/debt (%)	12.6	20.9	19.8

Table 1

Peer Comparison (cont.)

Industry sector: electric

	Kentucky Power Co.	Kentucky Utilities Co.	Louisville Gas & Electric Co.
FOCF/debt (%)	(1.8)	0.9	(4.4)
DCF/debt (%)			

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Financial Risk: Significant

KPCo benefits from various rate mechanisms that allow for the timely recovery of costs and support more stable operating cash flows. We expect the company will continue to fund its investments in a manner that preserves existing credit quality.

Under our base-case scenario, we anticipate KPCo's stand-alone adjusted FFO to debt in the 14%-16% range in 2020. Afterwards, we expect FFO to debt to improve thereafter to the 15%-17% range as the company benefits from recovery mechanisms like the environmental cost rider, as well as formula transmission rates and forward test years for rate cases. For 2020, we also forecast the company to have greater leverage with slightly higher debt to EBITDA in the low- to mid-5x range, only to fall to the higher 4x range thereafter. In addition, ongoing discretionary cash flow deficits after dividends and elevated capital spending are expected to be at least partly debt-funded.

We assess KPCo's financial risk under our medial volatility financial benchmarks, reflecting the company's lower-risk regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed compared with those used for a typical corporate issuer.

Table 2

Financial Summary

Industry sector: electric

	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
(Mil. $)					
Revenue	642.1	642.8	655.0	654.2	782.0
EBITDA	203.0	185.2	206.3	170.8	192.5
FFO	165.8	143.5	203.5	153.3	135.4
Interest expense	41.9	48.8	50.5	49.5	43.2
Cash interest paid	40.4	44.6	45.8	44.8	38.6
Cash flow from operations	118.2	124.5	158.6	135.2	212.3
Capital expenditure	134.8	94.5	98.8	113.4	99.9
FOCF	(16.6)	29.9	59.8	21.8	112.5
DCF	(16.6)	(5.1)	15.8	(22.2)	(2.5)
Cash and short-term investments	1.2	0.9	0.9	0.9	0.8
Gross available cash	1.2	0.9	0.9	0.9	0.8
Debt	938.0	926.9	920.0	940.1	919.4

Table 2

Financial Summary (cont.)

Industry sector: electric

	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
Equity	732.9	670.3	668.4	663.1	663.6
Adjusted ratios					
EBITDA margin (%)	31.6	28.8	31.5	26.1	24.6
Return on capital (%)	6.5	6.1	7.6	5.4	6.3
EBITDA interest coverage (x)	4.8	3.8	4.1	3.5	4.5
FFO cash interest coverage (x)	5.1	4.2	5.4	4.4	4.5
Debt/EBITDA (x)	4.6	5.0	4.5	5.5	4.8
FFO/debt (%)	17.7	15.5	22.1	16.3	14.7
Cash flow from operations/debt (%)	12.6	13.4	17.2	14.4	23.1
FOCF/debt (%)	(1.8)	3.2	6.5	2.3	12.2
DCF/debt (%)	(1.8)	(0.5)	1.7	(2.4)	(0.3)

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Liquidity: Adequate

We assess KPCo.'s stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. We believe KPCo has sound banking relationships, the ability to absorb high-impact, low probability events without the need for refinancing, and a satisfactory standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Estimated cash FFO of about $145 million. • Average available borrowing capacity from the AEP money pool of about $180 million.	• Debt maturities, including affiliate advances of about $65 million. • Capital spending of about $225 million.

Environmental, Social, And Governance

KPCo's carbon footprint is a significant environmental risk factor in the long run due to its high level of coal-based power generation. Of KPCo's 1,060 megawatts (MW) of owned generation capacity and 393 MW of purchased power capacity, coal contributes around 81%, and natural gas about 19%. The company's reliance on coal-fired generation exposes it to heightened risks, including the ongoing cost of operating older units in the face of disruptive technology advances, and the potential for significant capital investments to meet increasing environmental regulation. KPCo and parent AEP have begun to reduce reliance by retiring coal plants and investing in hydro, wind, solar, and energy efficiency. AEP's management is taking active steps to reduce the company's environmental footprint, committing to cutting carbon dioxide emissions to 80% of 2000 levels by 2050. Social and governance factors are consistent with what we see across the industry for other regulated utilities.

Group Influence

We consider KPCo to be a core subsidiary of AEP because it is highly unlikely to be sold, has a strong long-term commitment from senior management, is successful at what it does, and contributes meaningfully to the group. There are no meaningful insulation measures that protect KPCo from AEP. Therefore, our issuer credit rating on KPCo is in line with AEP's group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

Capital structure

KPCo's capital structure consists of about $900 million of debt.

Analytical conclusions

We rate KPCo's senior unsecured debt the same as the issuer credit rating because it is the debt of a qualified investment-grade utility.

Reconciliation

Table 3

Reconciliation Of Kentucky Power Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $)

	--12 months ended Sept. 30, 2018--									
Kentucky Power Co. reported amounts.										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
	879.6	719.8	653.8	202.5	106.6	37.9	202.5	143.6	8.8	135.1

Table 3

Reconciliation Of Kentucky Power Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $) (cont.)

S&P Global Ratings' adjustments

Interest expense (reported)	--	--	--	--	--	--	(37.9)	--	--	--
Interest income (reported)	--	--	--	--	--	--	(0.2)	--	--	--
Current tax expense (reported)	--	--	--	--	--	--	6.1	--	--	--
Operating leases	7.7	--	--	2.0	0.5	0.5	1.4	1.4	--	--
Postretirement benefit obligations/deferred compensation	--	--	--	(3.0)	(3.0)	--	(2.8)	(0.8)	--	--
Surplus cash	(0.7)	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	0.6	(0.6)	(0.6)	--	(0.6)
Asset retirement obligations	28.3	--	--	2.4	2.4	2.4	(5.4)	20.3	--	--
Non-operating income (expense)	--	--	--	--	2.5	--	--	--	--	--
Debt - accrued interest not included in reported debt	9.3	--	--	--	--	--	--	--	--	--
EBITDA - other	--	--	--	2.3	2.3	--	2.3	--	--	--
Total adjustments	44.5	0.0	0.0	3.6	4.7	3.6	(37.2)	20.3	0.0	(0.6)

S&P Global Ratings' adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Funds from Operations	Cash flow from operations	Dividends paid	Capital expenditures
	924.1	719.8	653.8	206.0	111.4	41.5	165.3	163.9	8.8	134.5

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/--

Business risk: Strong

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Satisfactory

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: bbb

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : bbb

- **Group credit profile:** a-
- **Entity status within group:** Core (+2 notches from SACP)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
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- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	**bbb**	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of April 8, 2020)*	
Kentucky Power Co.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	A-
Issuer Credit Ratings History	
02-Feb-2017	A-/Stable/--
16-Sep-2016	BBB+/Watch Pos/--
29-Sep-2014	BBB/Positive/--

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Common Equity Flotation Costs and Rate Making

By EUGENE F. BRIGHAM, DANA ABERWALD, and LOUIS C. GAPENSKI

The proper treatment of common stock flotation costs is an issue in almost every utility rate case, and becomes increasingly important – for reasons shown in this article – as new stock offerings decline. The article provides clarification of the issue and offers a reasonable solution.

Incorrect statements have been made about the proper treatment of common equity flotation costs in the financial literature, and this has contributed to incorrect rate case testimony and to several improper decisions. The problem seems to have arisen for two reasons: (1) During the 1970s, when most utilities were raising large amounts of equity, the case for an equity cost adjustment was generally based on the need to sell common stock at prices greater than book value so as to avoid dilution when new stock was sold, but the proper rationale for the adjustment, and the argument that should have been made, is that an adjustment is necessary to recover actual incurred costs. (2) A number of academic writers [1, 2, 3, 6, 7, 8, 11][1] have attempted to deal with the problem algebraically, and while a mathematical approach has merit, the different authors based their models on different and somewhat obscure assumptions, with the result that the academic research has actually done more to confuse than to clarify the issue.

As we see it, there are two questions which need answers:

1) Is an adjustment needed even if a company has no plans to sell new common stock in the foreseeable future?
2) If an adjustment is required, should it be applied to common stock only or to total common equity (common stock plus retained earnings)?

The answers are "yes" to the first question and "total common equity" to the second. Specifically, the market-determined cost of equity should be adjusted (increased) to reflect issuance costs associated with past issues regardless of whether a company plans to issue stock in the future or not, and the adjustment should be applied to the total common equity, including retained earnings. The reasons for these conclusions are set forth in the balance of this article.

[1]Numbers in brackets correspond to numbers in the list of references at the end of the article.

Background and Approach

The flotation cost adjustment – whether for bonds, preferred stocks, or common equity – is designed to convert a market rate of return into a fair rate of return on accounting book values. Prior to the 1970s, most utilities were regulated on the basis of the comparable earnings approach. With that method no market return was involved, and hence there was no need for a common equity flotation adjustment. However, as use of market-oriented equity cost approaches, especially the discounted cash flow (DCF) method, became prevalent during the 1970s, a specific flotation adjustment became necessary. The first use of DCF, to the authors' knowledge, was by Professor Myron J. Gordon as a staff witness in an American Telephone and Telegraph Company rate case before the Federal Communications Commission in the mid-1960s. Professors Alexander A. Robichek and Ezra Solomon of Stanford University, testifying for AT&T, proved that if a commission correctly identifies and then allows a *company* to earn its DCF cost of equity, k, on book equity, then *investors* will never be able to earn k on their investment, because the capital that investors have put up will exceed the company's book equity as a result of issuance (or flotation) costs. Thus, in the very first

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case where DCF methodology was used, Robichek and Solomon proved, and Gordon accepted, the idea that the allowed return on equity should exceed the DCF cost. Unfortunately, only the need for an adjustment, not the proper adjustment mechanism itself, was identified in that rate case.

The DCF method's great increase in popularity occurred during the 1970s, just when the companies were raising unprecedented amounts of new equity capital. Witnesses who used the DCF method recognized the need for an adjustment, and they had to provide a rationale to commissioners. Most witnesses gave this explanation:

1) If a company were allowed to earn only its DCF cost of equity, then its stock would normally sell at book value.
2) When new stock was issued, flotation expenses plus market pressure would drive the price of the stock below book value.
3) The issuance of stock at below book value would dilute the book value of the existing shares, and since future earnings and dividends are dependent upon book value, the market value of existing stock would also be diluted.
4) This dilution would obviously harm current stockholders; indeed, it would amount to economic confiscation.
5) Therefore, fair regulation requires commissioners to set authorized returns high enough to cause utility stocks to sell at prices that exceed book value by an amount sufficient to prevent below-book sales.

This argument was correct, although incomplete, and it was generally accepted during the 1970s, when most utilities were selling new stock every year or two. There were, of course, arguments about the level of flotation costs and the extent of market pressure, and hence about the proper market-to-book ratio, but the logic of some type of adjustment was rarely questioned.

However, as many utilities' construction programs neared completion in the early 1980s, and, accordingly, as new stock offerings slowed, the issue of the need for a flotation adjustment resurfaced. Patterson [6, 7] applied standard corporate finance techniques and concluded that a flotation adjustment is needed irrespective of current equity sales. Richter [11] supported Patterson's position. Arzac and Marcus [1, 2] also concluded that a flotation adjustment is always needed, but their formula produces an almost trivial adjustment factor unless the company is selling very large amounts of stock every year. Patterson and Arzac-Marcus debated in the finance journals, but they reached no reconciliation. Finally, in the latest article, Professors Bierman and Hass [3] derived yet another formula, one which produces an adjustment factor between those recommended by Patterson and Arzac-Marcus.

The issue is important, so it is necessary that we resolve the conflict. Further, since utility executives and regulators, not financial economists, must make decisions in this area, the resolution must be understandable to these decision makers. After studying the problem, we concluded that the best way to approach a clear resolution is to set up some hypothetical, but reasonable, situations and then to test the alternative theories, asking the following question: What results do the several methods produce, and are those results fair to both consumers and investors?

Bonds and Preferred Stocks

Because the proper treatment of flotation costs on bonds and preferred stocks is well known and not controversial, it helps to begin by examining that treatment as a lead-in to the analysis of common stock. First, note that debt flotation costs can be recovered in either of two ways: (1) They can be expensed and recovered from customers during the year the securities are sold, or (2) They can be capitalized and recovered over the life of the securities. The second method, which is consistent with the theory that those customers who benefit from a cost should pay for it, is generally used. Under this theory, bond flotation expenses are reflected in the embedded cost of the bond and are recovered over the life of the bond. For example, if flotation costs of 5 per cent were incurred on a \$100 million, ten-year, 15 per cent coupon bond issue, they would be handled in the following manner by most federal and state regulators:

$$\text{Cost to company} = \frac{\text{Interest expense + Amortization of flotation costs}}{\text{Principal value} - \text{Unamortized flotation costs}} \quad (1)$$

$$= \frac{\$15{,}000{,}000 + (\$5{,}000{,}000/10)}{\$100{,}000{,}000 - \$5{,}000{,}000}$$

$$= \frac{\$15{,}500{,}000}{\$95{,}000{,}000} = 16.3158\% \text{ for the first year}$$

Return requirements would be calculated as follows:

$$\text{Return requirements} = \text{Cost rate(Principal value} - \text{Unamortized flotation costs)} \quad (2)$$

$$= 0.163158(\$100{,}000{,}000 - \$5{,}000{,}000)$$

$$= \$15{,}500{,}000.$$

In this example, the company received \$95 million of cash, which it used to purchase \$95 million of operating assets. To meet its interest expense and flotation amortization requirements, the company must have \$15.5 million in return dollars. This return will only be generated if the company earns 16.3158 per cent on its \$95 million of operating assets. Under this procedure, the percentage cost as calculated in Equation 1 declines each year, but the return dollar amount remains constant.[2]

[2]An alternative procedure that produces exactly the same result is to divide interest charges plus flotation amortization by the principal value of the issue, and then to multiply this cost rate by the principal value of the issue:

$$\text{Embedded cost rate} = \frac{\$15{,}500{,}000}{\$100{,}000{,}000} = 0.155 = 15.5\%.$$

$$\text{Return requirements} = 0.155(\$100{,}000{,}000) = \$15{,}500{,}000.$$

This procedure in effect includes both flotation costs and operating assets in the rate base.

Preferred stocks are handled similarly. Actually, utilities issue two types of preferred stocks, those with sinking funds and those that are perpetual. The adjustment formula for sinking fund preferred is exactly like that for bonds, but a difference arises in the case of perpetual preferreds. Perpetual preferred stock represents permanent capital; hence its flotation costs are not amortized.[3] Assuming again a $100 million issue and a 5 per cent flotation cost, this formula applies:

$$\text{Cost to company} = \frac{\text{Dividend requirements}}{\text{Net proceeds}} = \frac{\$15{,}000{,}000}{\$95{,}000{,}000} \quad (3)$$

$$= 15.7895\%$$

Alternatively, we could write the formula as follows:

$$\text{Cost to company} = \frac{\text{Dividend rate}}{1.0 - \text{Flotation}} = \frac{15\%}{0.95} = 15.7895\% \quad (3a)$$

The return dollars can then be calculated as follows:[4]

$$\text{Dollars of return} = 0.157895(\$95{,}000{,}000) = \$15{,}000{,}000.$$

In this example, the preferred stockholders expect and require a return of 15 per cent on ***their investment*** ($100 million), but the company must earn 15.7895 per cent on *its operating assets* ($95 million) to provide this required return.[5] If the company earned only 15 per cent on the $95 million, then the company would have after-tax revenues of only $14,250,000 to meet investors' preferred dividend requirements of $15 million. Obviously, then, the 15 per cent market value cost of preferred must be adjusted upward to a 15.7895 per cent return on the company's operating assets if investors are to receive the reasonable rate of return they contracted for.

Common Stock

From a conceptual standpoint, it has long been recognized that the situation with common stock is similar to that for bonds and preferred stocks: Issuance costs are incurred; they should not be and are not expensed at the time the stock is sold; and therefore recovery must occur in subsequent years. Further, just as with bonds and preferred stock, the authorized rate of return on rate base equity must be above the rate of return to the investor; that is, the cost to the utility is above the return to the investor. The standard textbook formula, which Patterson [6] used, is as follows:[6]

$$r = \frac{\text{Expected dividend yield}}{1.0 - F} + g \quad (5)$$

Here:

r = authorized rate of return on book equity, if stockholders are to earn their required rate of return, k,
F = percentage flotation cost associated with common stock offerings, and
g = the expected growth rate in earnings and dividends.

The percentage flotation factor, F, consists of two elements: (1) underwriting costs and (2) "market pressure," which is the decline in the stock price that results when the supply of shares is suddenly increased. Historically, utility underwriting expenses have averaged from 3 to 4 per cent of gross proceeds [9]. Market pressure varies over time, depending on the size of the issue, the condition of the market, and the degree to which investors were surprised by the announcement of the stock sale. Moreover, stock prices change for reasons other than new offerings, so it is difficult to obtain an exact measure of market pressure. However, several careful studies have been reported, and they indicate that market pressure is in the range of one to 3 per cent [10]. Thus, for most utilities, flotation expenses plus pressure have totaled about 5.5 per cent.

To illustrate the flotation cost adjustment process, and following Bierman and Hass for consistency, we assume that a new, start-up utility has the following characteristics:

1) Our hypothetical company can sell stock in the market at $10 per share, and investors expect it to pay a dividend of one dollar and to grow at a rate of 5 per cent. Thus, its DCF cost of equity is $k = D/P + g = 10\% + 5\% = 15\%$, investors' required rate of return.
2) To raise initial capital, the company plans to sell an issue of stock, incurring flotation costs of F = 5 per cent.
3) Applying Equation 5, we obtain a flotation-adjusted cost of equity (r) of 15.5263 per cent:

$$r = \frac{\text{Expected dividend yield}}{1 - F} + g$$

$$= \frac{10.0\%}{0.95} + 5\%$$

$$= 10.5263\% + 5\% = 15.5263\%$$

Thus, the illustrative utility's fair rate of return on book equity according to Equation 5 is approximately 53 basis points above its 15 per cent unadjusted "bare bones DCF cost of equity."
4) The company will sell one share of stock and obtain net proceeds of $9.50. This $9.50 is also the initial book value, B, and rate base. (Obvi-

[3]In effect, the flotation costs of the preferred are amortized over an infinite period, which is to say the amortization per year is zero. Investors have made a *permanent* investment, so the original investors or those who purchase the stock in the secondary market must receive a return on that investment in perpetuity.

[4]Of course, preferred stock dividends are not deductible, so the total revenues required to produce the return dollars is higher for preferred stock than for debt.

[5]Note that the return dollars for the bond exceed those for the perpetual preferred stock – $15.5 million versus $15 million. However, these are first-year costs only. The bond's cost rate declines over time due to the amortization of its flotation costs, whereas the cost rate associated with the preferred stock remains constant, and the rates of return to the bondholders and the preferred stockholders are identical.

[6]This formula is developed in reference citation 5, Chapter 7, as well as in most other corporate finance textbooks.

ously, this amount, which we use for simplicity, could be scaled up without altering the conclusions.)

5) After its inception and initial stock offering, all of the company's equity is expected to come from retained earnings. In a later case, we will examine the situation when more stock is sold.
6) The company operates in a reasonable and prudent manner, such that by any fairness criteria, investors should be allowed to earn their 15 per cent cost of capital return, no more and no less. For simplicity, we also assume that regulation operates properly, without lags.
7) Initially, we assume that the market cost of capital remains constant at 15 per cent, and that the company maintains a constant payout ratio so as to keep the dividend yield and growth components at 10 per cent and 5 per cent, respectively. These assumptions are consistent with the DCF model, but later in the article we expand the analysis by relaxing both of them.

Now these questions may be asked:

Should the flotation adjustment be applied to all common equity or, once retained earnings appear on the balance sheet, only to common stock?
For how many years should an adjustment be applied: One, two, ten, twenty, or forever?

When we applied Equation 5, the textbook formula which Patterson recommended, we found that it produces results that satisfy the fairness criterion; namely, it permits investors to earn exactly their 15 per cent cost of capital, no more and no less. This result for our initial case is demonstrated in Table 1, which was produced by a simple computer model, and it is analyzed below:

Table 1

Case 1: Company Earns Flotation-adjusted Cost of Equity (r) on All Common Equity

Beginning of Year

Year	Common Stock (1)	Retained Earnings (2)	Total Equity (3)	Stock Price (4)	Market-Book Ratio (5)	EPS (6)	DPS (7)	Payout (8)
1	$9.50	$0.0000	$ 9.5000	$10.0000	1.0526x	$1.4750	$1.0000	67.7966%
2	9.50	0.4750	9.9750	10.5000	1.0526	1.5488	1.0500	67.7966
3	9.50	0.9738	10.4738	11.0250	1.0526	1.6262	1.1025	67.7966
4	9.50	1.4974	10.9974	11.5763	1.0526	1.7075	1.1576	67.7966
5	9.50	2.0473	11.5473	12.1551	1.0526	1.7929	1.2155	67.7966
6	9.50	2.6247	12.1247	12.7628	1.0526	1.8825	1.2763	67.7966
7	9.50	3.2309	12.7309	13.4010	1.0526	1.9766	1.3401	67.7966
8	9.50	3.8675	13.3675	14.0710	1.0526	2.0755	1.4071	67.7966
9	9.50	4.5358	14.0358	14.7746	1.0526	2.1792	1.4775	67.7966
10	9.50	5.2376	14.7376	15.5133	1.0526	2.2882	1.5513	67.7966

NOTES:
1) Assumptions made in this case are as follows:
   a) Issue price = $10
   b) Flotation cost = 5%
   c) k = D/P + g = 10% + 5% = 15%
   d) r = 15.5263%
2) The data in this case, and also the more complex cases, were developed with a Lotus 1-2-3 computer program.

1) The company's balance sheet item common stock is shown in Column 1.
2) Retained earnings are shown in Column 2. Initially, they are zero, but they build up over time.
3) Total equity as shown in Column 3 is the sum of common stock and retained earnings. Total equity grows as retained earnings build up.
4) Column 4 shows the stock price as determined by the basic DCF formula. It starts at $10 and grows at a rate of 5 per cent per year, which is necessary to produce the 5 per cent capital gains yield that investors expect and should receive.[7]
5) Column 5 shows the market-to-book (M/B) ratio. Notice that the M/B always exceeds one. The only way the M/B ratio could go to one would be for the stock price to fall below the value shown in Column 4, but if that were to happen, then investors would not receive the capital gains to which they are entitled. Thus, the M/B will exceed one if investors are being treated fairly.
6) Earnings per share (EPS) as shown in Column 6 is the product of total equity times 0.155263, the fair rate of return as determined by Equation 5.
7) Dividends per share (DPS) as shown in Column 7 begin at one dollar and grow at a rate of 5 per cent per year. This growth rate is a requirement if investors are to earn their DCF cost of capital.
8) The payout ratio is shown in Column 8. Under

[7]The DCF valuation equation is

$$P_0 = \frac{D_1}{k - g}$$

This equation, solved for k, produces the standard DCF cost of capital equation, $k = D_1/P_0 + g$. See reference citation 5, Chapter 5, for a derivation and discussion.

the assumptions of the standard DCF constant growth model, the payout must be constant, and it is if r as determined by Equation 5 is used as the allowed return on equity.

9) Note also that book value per share as shown in Column 3 is growing at a constant rate, 5 per cent. The retention growth rate, $g = br$, where r is the return on book equity and b is the fraction of earnings, is

$$g = br = (1.0 - 0.677966)(15.5263) = 0.322(15.5263) = 5.0\%,$$ just as it should be.

Case 1 proves that Equation 5 produces the desired results: namely, returns that exactly cover the cost of equity, no more and no less. Any return on book equity different from that established by Equation 5 would produce inconsistent results. For example, suppose the authorized rate of return were cut from 15.5263 to the DCF return, 15 per cent, in Year 2. This would cause the stock price to drop from $10.50 to the $9.9750 book value. Thus, stockholders would suffer a loss, and they would not obtain the capital gains yield to which they are entitled. Any other type of experimentation will show exactly the same thing: If the company is not allowed to earn the cost of equity as determined by Equation 5 on total common equity, stockholders will not receive a 15 per cent return on their invested capital.

Sale of Additional Equity

While the only-one-equity-sale conditions used to develop Case 1 are consistent with Bierman and Hass's example, and also with some actual companies such as Comsat and the Yankee Atomic Power companies, most utilities sell additional common stock from time to time. Therefore, we modified the computer model to analyze stock sales subsequent to the initial offering, and we report the results in Table 2 as Case 2, in which the company raises an additional share of new common equity for $12.1247 at the beginning of Year 6. (Note that the $12.1247 is calculated as the price of the stock at the beginning of Year 6 less flotation costs.) Earnings, dividends, and common equity all increase in Year 6 as a result of the sale, but investors continue to earn exactly 15 per cent on their investment so long as the company is allowed to earn 15.5263 per cent on its total book equity.

In Case 3, reported in Table 3, we present the results for a company that issues new equity at a flotation cost different from the cost of its original stock issue. Case 3 is similar to Case 2. Just as in Case 2, the company issues new equity at the beginning of Year 6. However, in Case 3, the equity sold at the beginning of Year 6 has a different flotation cost (3 per cent) from that of the original issue (5 per cent). With lower flotation costs, the company nets more common equity in Case 3 than in Case 2. (The dollar amount of new equity raised is calculated as the price of the share of stock at the beginning of Year 6 less the 3 per cent flotation costs incurred.)

In this example, because the new equity is sold at a different flotation cost than the old equity, a new value of r must be calculated and used to determine net income. The new r is a weighted average of r as determined by Equation 5 for each equity issue, with the weights being the fraction of total equity attributable to the new and old stock at the time the new stock is issued. Because of the lower flotation costs on the new equity, there is a corresponding drop in the market-to-book ratio in Year 6. Note, however, that after the transitional Year 6, earnings and dividends continue to grow at the required 5 per cent rate, which is neces-

Table 2

Case 2: Company Sells Additional Stock at the Beginning of Year 6

Beginning of Year

Year	Common Stock (1)	New Issue (1a)	Retained Earnings (2)	Total Equity (3)	Stock Price (4)	Market-Book Ratio (5)	EPS (6)	DPS (7)	Payout Ratio (8)
1	$ 9.50		$0.0000	$ 9.5000	$10.0000	1.0526x	$1.4750	$1.0000	67.7966%
2	9.50		0.4750	9.9750	10.5000	1.0526	1.5488	1.0500	67.7966
3	9.50		0.9738	10.4738	11.0250	1.0526	1.6262	1.1025	67.7966
4	9.50		1.4974	10.9974	11.5763	1.0526	1.7075	1.1576	67.7966
5	9.50		2.0473	11.5473	12.1551	1.0526	1.7929	1.2155	67.7966
6	9.50	$12.1247	2.6247	24.2493	12.7628	1.0526	1.8825	1.2763	67.7966
7	21.6247		3.8371	25.4618	13.4010	1.0526	1.9766	1.3401	67.7966
8	21.6247		5.1102	26.7349	14.0710	1.0526	2.0755	1.4071	67.7966
9	21.6247		6.4470	28.0717	14.7746	1.0526	2.1792	1.4775	67.7966
10	21.6247		7.8506	29.4752	15.5133	1.0526	2.2882	1.5513	67.7966

NOTES:
Assumptions made in this case are as follows:
a) Original issue price = $10
b) Flotation cost = 5%
c) k = D/P + g = 10% + 5% = 15%
d) r = 15.5263%
e) Year 6 issue price = $12.7628
f) Year 6 new common stock = $12.7628(1 − F)
= $12.7628(0.95)
= $12.1247

Table 3

Case 3: Company Sells Additional Stock at the Beginning of Year 6 Incurring Different Flotation Costs

Beginning of Year

Year	Common Stock (1)	New Issue (1a)	Retained Earnings (2)	Total Equity (3)	Stock Price (4)	Market-Book Ratio (5)	EPS (6)	DPS (7)	Payout Ratio (8)
1	$ 9.5000		$0.0000	$ 9.5000	$10.0000	1.0526x	$1.4750	$1.0000	67.7966%
2	9.5000		0.4750	9.9750	10.5000	1.0526	1.5488	1.0500	67.7966
3	9.5000		0.9738	10.4738	11.0250	1.0526	1.6262	1.1025	67.7966
4	9.5000		1.4974	10.9974	11.5763	1.0526	1.7075	1.1576	67.7966
5	9.5000		2.0473	11.5473	12.1551	1.0526	1.7929	1.2155	67.7966
6	9.5000	$12.3799	2.6247	24.5046	12.7628	1.0526	1.8889	1.2763	67.7566
7	21.8799		3.8499	25.7298	13.4010	1.0526	1.9833	1.3401	67.5676
8	21.8799		5.1364	27.0163	14.0710	1.0526	2.0825	1.4071	67.5676
9	21.8799		6.4872	28.3671	14.7746	1.0526	2.1866	1.4775	67.5676
10	21.8799		7.9056	29.7855	15.5133	1.0526	2.2960	1.5513	67.5676

NOTES:
Assumptions made in this case are as follows:
a) Original issue price = $10
b) Year 1 Flotation cost = 5%
c) k = D/P + g = 10% + 5% = 15%
d) r_1 = 15.5263%
e) Year 6 issue price = $12.7628
f) Year 6 flotation cost = 3%
g) Year 6 new common stock = $12.7628(1 − F)
= $12.7628(0.97)
= $12.3799
h) Additional issue r = 15.3093%

sary if investors are to receive the 15 per cent DCF return on their investment. The stock price grows at 5 per cent throughout the ten-year period.

The fact that the company must continue to earn the flotation-adjusted cost of equity, even as retained earnings build up to a larger and larger proportion of total common equity, is counterintuitive, and so it deserves further discussion. Here are two comments:

1) *Demonstration that a weighted average cost rate is inappropriate.* It has been suggested that the authorized return on equity should be a weighted average of the flotation-adjusted cost rate, r = 15.5263 per cent, and the DCF cost rate, k = 15 per cent, with the weights being based on common equity and accumulated retained earnings, respectively. When we programmed our model to reflect these conditions, we obtained the results shown in Table 4. A problem obviously exists – if dividends are to grow at the 5 per cent rate that investors expect, and if earnings are based on a weighted average of k and r, then a higher and higher percentage of earnings will have to paid out. Thus, the payout ratio will rise. In Year 34 the payout ratio will exceed 100 per cent, so retained earnings will start to decline. Retained earnings actually go negative in Year 45, and Total Common Equity goes negative in Year 46, which means the company is officially bankrupt. This example demonstrates, in yet another way, that the flotation-adjusted cost of equity must be earned on all common equity if investors are to receive the DCF return to which they are entitled under prudent management. The example also demonstrates that, if investors were informed that the regulatory treatment implied in Table 4 were going to be employed, they would not invest in the company in the first place.

2) *Logical explanation.* To understand *why* the Equation 5 value must be applied to all common equity, retained earnings as well as equity raised by selling stock, one must trace through the valuation process. Notice that, in Year 1, investors require a return of 15 per cent on their $10 investment, or $1.50. However, the company earns only $1.4750, of which it pays out one dollar as a dividend and retains 47.5 cents. To give the investor the fifty-cent increase in market value (or capital gain) needed to add to the one dollar dividend to produce the $1.50, or 15 per cent, total DCF return, the 47.5 cents must earn more than 15 per cent. Specifically, it must earn the flotation adjusted cost of equity, r = 15.5263 per cent. This same thought process can be continued in other years, ad infinitum, and the ultimate conclusion is that both the original common equity and all retained earnings must earn r = 15.5263 per cent.

If the preceding paragraph is not clear, we can put it another way. The investor expects and is entitled to earn, under prudent management, a return of 15 per cent on his or her investment. Thus, dividends plus capital gains must total 15 per cent, or $1.50 in the first year. Ten per cent, or one dollar, will come from dividends, so 5 per cent, or 50 cents, must come from capital gains. To obtain a capital gain yield of 50 cents from 47.5 cents of retained earnings, the retained earnings must earn a return greater than k = 15 per cent; specifically, the retained earnings must be allowed to earn r = 15.5263 per cent. (If the 47.5 cents earned 15 per cent, then it would be worth exactly 47.5 cents, not 50 cents.) In Year 2, retained earnings will rise by

5 per cent from 47.5 cents to 49.875 cents; the capital gains then must rise from 50 cents to .50(1.05) = 52.5 cents; the only way this can happen is for the second-year retained earnings to be allowed to earn r = 15.5263 per cent; and so on.

The Effect of the Payout Ratio on the Flotation Cost Adjustment

Even though fair regulation requires that retained earnings be allowed to earn the flotation adjusted cost of equity, the level of retained earnings as affected by the payout ratio does have a material effect on the size of the adjustment.

To illustrate this point, assume (1) that two utilities both have a 15 per cent market cost of equity, that is, k = 15 per cent; (2) that both companies sell at a price of $20; but (3) that one company has a policy of paying out 25 per cent of its earnings and retaining 75 per cent, while the other has the reverse dividend policy. Assume further that both companies earn 15 per cent on their $20 market value, so earnings per share are .15($20) = $3. The high payout company has a dividend of .75($3) = $2.25, while the low payout company has a dividend of .25($3) = 75 cents. At the same time, the low payout company, which plows most of its earnings back into the business, will have a growth rate of g = .75(15 per cent) = 11.25 per cent, while the high payout company will have g = .25(15 per cent) = 3.75 per cent.

Under these conditions, the following situation would exist for the two illustrative companies:

Low payout Company: $$k = \frac{D_1}{P_0} + g = \frac{\$0.75}{\$20} + 11.25\%$$

$$= 3.75\% + 11.25\% = 15\%$$

High payout Company: $$k = \frac{D_1}{P_0} + g = \frac{\$2.25}{\$20} + 3.75\%$$

$$= 11.25\% + 3.75\% = 15\%$$

Applying the adjustment formula,

$$r = \frac{\text{Expected dividend yield}}{1 - F} + g,$$

we find this situation, assuming that issuance costs are 5 per cent:

High payout Company: $$r = \frac{11.25\%}{0.95} + 3.75\%$$

$$= 11.842\% + 3.75\% = 15.592\%$$

Low payout Company: $$r = \frac{3.75\%}{0.95} + 11.25\%$$

$$= 3.947 + 11.25\% = 15.197\%$$

Difference = 0.395%

Thus, we see that the company which retains most of its earnings, and which consequently has more retained

Table 4

Case 4: Company Earns Weighted Average k

Year	Common Stock (1)	Retained Earnings (2)	Total Equity (3)	EPS (4)	DPS (5)	Payout Rate (6)	Weighted k (7)
1	$9.5000	$ 0.0000	$ 9.5000	$1.4750	$1 0000	67.7966%	0.1553
2	9.5000	0.4750	9.9750	1.5463	1.0500	67.9062	0.1550
3	9.5000	0.9713	10.4713	1.6207	1.1025	68.0267	0.1548
4	9.5000	1.4894	10.9894	1.6984	1.1576	68.1591	0.1545
5	9.5000	2.0302	11.5302	1.7795	1.2155	68.3047	0.1543
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
33	9.5000	23.2219	32.7219	4.9583	4.7649	96.1006	0.1515
34	9.5000	23.4152	32.9152	4.9873	5.0032	100.3188	0.1515
35	9.5000	23.3993	32.8993	4.9849	5.2533	105.3852	0.1515
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
45	9.5000	−2.3443	7.1557	1.1234	8.2791	736.9935	0.1570
46	The company goes bankrupt.						

NOTES:

1) Assumptions made in this case are as follows:
   a) Issue price = $10
   b) Flotation cost = 5%
   c) k = D/P + g = 10% + 5% = 15%
   d) r = 15.5263%
2) The dividend in Year 45 cannot grow by the 5 per cent growth rate, because if it did total equity would become negative. Therefore, the Year 45 dividend is calculated as the remaining portion of total equity + earnings in Year 45: $7.1557 + $1.1234 = $8.2791.

Table 5

Case 5: Company Sells Additional Stock and k Changes

Beginning of Year

Year	Common Stock (1)	New Issue (1a)	Retained Earnings (2)	Total Equity (3)	Stock Price (4)	Market-Book Ratio (5)	EPS (6)	DPS (7)	Payout Ratio (8)
1	$ 9.5000		$0.0000	$ 9.5000	$10.0000	1.0526x	$1.4750	$1.0000	67.7966%
2	9.5000		0.4750	9.9750	10.5000	1.0526	1.5488	1.0500	67.7966
3	9.5000		0.9738	10.4738	11.0250	1.0526	1.6262	1.1025	67.7966
4	9.5000		1.4974	10.9974	11.5763	1.0526	1.7075	1.1576	67.7966
5	9.5000		2.0473	11.5473	12.1551	1.0526	1.7929	1.2155	67.7966
6	9.5000	$12.3799	2.6247	24.5046	12.7628	1.0526	1.8889	1.2763	67.5676
7	21.8799		3.8499	25.7298	13.4010	1.0526	1.9833	1.3401	67.5676
8	21.8799		5.1364	27.0163	14.0710	1.0526	1.8123	1.4071	77.6398
9	21.8799		5.9469	27.8268	14.4931	1.0526	1.8667	1.4493	77.6398
10	21.8799		6.7817	28.6616	14.9279	1.0526	1.9227	1.4928	77.6398

NOTES:
Assumptions made in this case are as follows:
a) Original issue price = $10
b) Year 1 flotation cost = 5%
c) Issue 1 r = 15.5263%
d) Year 6 issue price = $12.7628
e) Year 6 flotation cost = 3%
f) Year 6 new common stock = $12.7628(1 − F)
= $12.7628(0.97)
= $12.3799
g) Additional issue r = 15.3093%
h) Years 1-7, k = D/P + g = 10% + 5% = 15%
i) Years 8-10, k = D/P + g = 10% + 3% = 13%

Table 6

Case 6: Company Sells Additional Stock and k Changes

Beginning of Year

Year	Common Stock (1)	New Issue (1a)	Retained Earnings (2)	Total Equity (3)	Stock Price (4)	Market-Book Ratio (5)	EPS (6)	DPS (7)	Payout Ratio (8)
1	$ 9.5000		$0.0000	$ 9.5000	$10.0000	1.0526x	$1.4750	$1.0000	67.7966%
2	9.5000		0.4750	9.9750	10.5000	1.0526	1.5488	1.0500	67.7966
3	9.5000		0.9738	10.4738	11.0250	1.0526	1.6262	1.1025	67.7966
4	9.5000		1.4974	10.9974	11.5763	1.0526	1.7075	1.1576	67.7966
5	9.5000		2.0473	11.5473	12.1551	1.0526	1.7929	1.2155	67.7966
6	9.5000	$12.3799	2.6247	24.5046	12.7628	1.0526	1.8889	1.2763	67.5676
7	21.8799		3.8499	25.7298	13.4010	1.0526	1.9833	1.3401	67.5676
8	21.8799		5.1364	27.0163	14.0710	1.0526	1.8011	1.1257	62.5000
9	21.8799		5.9469	27.3671	14.7746	1.0526	1.8911	1.1820	62.5000
10	21.8799		6.7817	29.7855	15.5133	1.0526	1.9857	1.2411	62.5000

NOTES:
Assumptions made in this case are as follows:
a) Original issue price = $10
b) Year 1 flotation cost = 5%
c) Issue 1 r = 15.5263%
d) Year 6 issue price = $12.7628
e) Year 6 flotation cost = 3%
f) Year 6 new common stock = $12.7628(1 − F)
= $12.7628(0.97)
= $12.3799
g) Additional issue r = 15.3093%
h) Years 1-7, k = D/P + g = 10% + 5% = 15%
i) Years 8-10, k = D/P + g = 10% + 3% = 13%

earnings and a smaller dollar amount of flotation costs, also has the lower flotation-adjusted cost of equity. This demonstrates that the issuance cost adjustment formula is itself adjusted to reflect the extent to which a company finances by retaining earnings rather than by selling new common stock.

Changes in the DCF Cost of Equity

We also analyzed the effects of changes in the DCF cost of equity over time. While a change in the DCF k causes a change in earnings, dividends, and the growth rate, the flotation adjustment *process* is not affected – Equation 5 still produces a fair rate of return on book value. This is demonstrated in Tables 5 and 6. It should be noted that the effects of the adjustment as derived by Equation 5 do vary with the level of the DCF cost and with the split between dividend yield and growth. In Case 5, we analyze the effects of a change in the growth rate with the dividend yield held constant, while in Case 6, reversing them, we analyze the effects of a change in the dividend yield with the growth rate held constant. Both cases use Case 3 as their base case. In each instance, a new value for r, based on Equation 5, can be established, and this return on book value permits investors to earn their new DCF cost of equity.

Capitalizing Flotation Costs

Bierman and Hass, almost as an afterthought toward the end of their article, suggested that utilities should be allowed to record the *gross amount* of equity sales and to earn a DCF return on gross equity capital. This would amount to capitalizing flotation costs. These capitalized costs could then be amortized over some prescribed period or else be kept on the books indefinitely.

To show this, we set up computer models using our various cases but capitalizing flotation costs. One can see that earnings, dividends, and stock prices are all exactly like those shown in our tables. Thus, capitalizing flotation costs produces exactly the same results as Equation 5.

Capitalizing flotation costs has much to recommend it, for it would eliminate the confusion that has existed. However, a fundamental problem exists for any company that has incurred flotation costs in the past, that is, for virtually the entire utility industry: How would the fact that past flotation costs were not capitalized be dealt with? In other words, capitalizing flotation costs would be an excellent procedure for a new, start-up, company, but such a plan would not be feasible for an existing company without somehow adjusting for past costs. Such an adjustment could be made, but a discussion of it goes beyond the scope of this article.

Conclusion

The proper treatment of equity flotation costs has caused much confusion. Had such costs been either capitalized in the past or else expensed on an as-incurred basis, there would be no problem, but since neither of these practices has generally been followed, the DCF return must be adjusted to produce a fair rate of return on book equity.

Further, the adjustment is always required, irrespective of whether or not a company has plans to sell new stock in the future, and the adjusted return must be earned on total equity, including retained earnings. Otherwise, it would be impossible for investors to earn the cost of equity, even under prudent and efficient management.

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NEW REGULATORY FINANCE

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Alternative Sources of Equity

A second controversy is whether a flotation cost allowance should be allowed because a company can always obtain equity from sources other than a public issue of common stock, such as a rights issue for example. There are several sources of equity capital available to a firm, including: public common stock issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure.

Equity capital raised through a public issue is typically more expensive than alternate sources of equity. Rights issues, when available, are less expensive, but direct costs still would be incurred. Of course, a rights issue assumes that a willing underwriter and a willing market could be found for such offerings in the first place, an unlikely event in public capital markets for small unproven companies. Internal sources of equity, including dividend reinvestment and/or employee stock option plans, are also typically less expensive, unless a discount on the purchase price is inherent in the plan, in which case they are often equivalent to a public issue. Direct costs are also incurred in an employee stock savings plan and/or a shareholder dividend reinvestment plan.

The flotation cost allowance is still warranted, however, because it is a composite factor that reflects the historical mix of all these sources of equity. The flotation cost allowance applicable to all the company's book equity is actually a weighted average of the current allowances required for each past financing, that is, the flotation cost allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity source. However, it is impractical and prohibitive to start from the inception of a company and source all present equity from various equity vintages and types of equity capital raised by the company. One way of circumventing the problem of vintaging each form of equity is to source book equity by broad categories of equity, such as dividend reinvestment plan equity, stock option equity, and public issue equity, and calculate a weighted average flotation factor. That is also onerous and cumbersome. A practical solution is to rely on the results of the empirical studies discussed earlier that quantify the average flotation cost factor of a large sample of utility stock offerings.

Efficient Markets

A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

Existing shareholders are made worse off when a company issues new stock below the market price, irrespective of how "efficient" that stock price may be. As seen in an earlier example, the new issue results in a transfer of wealth from existing to new shareholders. This is true regardless of the degree of efficiency of the market.

It has also been argued that a flotation cost allowance is inequitable since it results in a windfall gain to shareholders. This argument is erroneous. As stated previously, the company's common equity account is credited by an amount less than the market value of the issue, so that the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders. Moreover, existing shareholders are made worse off when a company issues new stock below the market price.

The suggestion that the flotation cost allowance is unwarranted because investors factor this shortcoming in the stock price implies that it is appropriate to use a deficient model because such a deficiency is reflected in stock prices. In other words, it is appropriate to use a deficient model because investors are aware of this. Such circular reasoning could be used to justify any regulatory policy. For example, under this reasoning, it would be appropriate to authorize a return on equity of 1% because investors reflect this fact in the stock price. This is clearly illogical and erroneous. Any regulatory policy, as irrational as it may be, can be justified using this argument.

Absence of Imminent Stock Issues

Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. If the flotation costs of past stock issues have been fully recovered, the argument has merit. If that assumption is not met, the argument is without merit. The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.